108 FERC ¶ 61,236
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. ER04-691-000, ER04-106-002

Public Utilities With Grandfathered Agreements in the Midwest ISO Region — Docket No. EL04-104-000

ORDER ADDRESSING TREATMENT OF GRANDFATHERED AGREEMENTS IN THE MIDWEST ISO ENERGY MARKETS, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued September 16, 2004)

TABLE OF CONTENTS

1. On March 31, 2004, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) filed a proposed Open Access Transmission and Energy Markets Tariff (TEMT) pursuant to section 205 of the Federal Power Act (FPA).[1] The proposed TEMT contains the terms and conditions necessary to implement a market-based congestion management program and energy spot markets, including a Day-Ahead Energy Market and a Real-Time Energy Market (collectively, Energy Markets), with locational marginal pricing (LMP) and Financial Transmission Rights (FTRs) for hedging congestion costs. In its application, the Midwest ISO estimated that up to 40,000 MW of transmission service capacity (approximately 40 percent of total Midwest ISO load) is provided under an estimated 300 grandfathered agreements (GFAs) currently effective in the Midwest ISO region.[2] The Midwest ISO argued that allowing GFA-holders scheduling rights similar to their current practice would require a physical reservation, or "carve-out," of transmission capacity in the Day-Ahead Energy Market and until the scheduling deadline prior to real-time dispatch. It stated that this carve-out would impair the reliability of the operation of its markets and would impose additional financial costs on parties to non-GFA transactions. Therefore, the Midwest ISO proposed to require GFA parties to schedule and settle their GFA transactions under the Midwest ISO's Energy and FTR Markets through one of three options.[3]

[1] 16 U.S.C. § 824d (2000).

[2] *See* Midwest ISO's March 31, 2004 TEMT filing at 9-10 (March 31 Filing).

[3] As discussed more fully below, Option A of the TEMT requires the GFA Responsible Entity to nominate and hold FTRs in order to transact under GFAs. The Midwest ISO assesses congestion charges and the cost of losses for all transactions under the GFA. Option B provides that the GFA Responsible Entity will not nominate or receive FTRs. The Midwest ISO will charge the GFA Responsible Entity the cost of congestion for all transactions pursuant to the GFA, but, if the GFA Scheduling Entity submits the bilateral transaction schedule a day ahead, the Midwest ISO will credit back to the GFA Responsible Entity the costs of congestion resulting from day-ahead

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2. On May 26, 2004, the Commission issued an order on the Midwest ISO's proposed TEMT and, among other things, initiated, under section 206 of the FPA,[4] a three-step process to address the treatment of transmission service provided under the GFAs in the Midwest ISO Energy and FTR Markets and offered an option for GFA parties to settle.[5] Further, the Commission set the date for implementation of the Energy Markets at March 1, 2005.[6]

3. The purpose of this order, Step 3 of the process, is to address how GFAs will be treated in the Midwest ISO Energy and FTR Markets. We have analyzed the contract information resulting from the fact-finding investigation of GFA contract terms in Steps 1 and 2 of the process and have divided the GFAs into several categories with differing consequences for their treatment in the Midwest ISO's Energy and FTR Markets, based either on their election to settle, actions by the presiding judges in the hearing held in Step 2, or our determinations in this order.

4. As discussed below, while the Midwest ISO had initially estimated that up to 40,000 MW of transmission service (40 percent of total Midwest ISO load) is provided under the GFAs, the results of the fact finding investigation conducted in Steps 1 and 2 indicate that only approximately 25,000 MW of transmission service (23 percent of total Midwest ISO load) is provided under 229 GFAs that will remain in effect on March 1, 2005, when the Midwest ISO commences operation of its Energy Markets. Of this 25,000 MW of transmission service, by our actions in this order, approximately 9,700 MW (9 percent of total MISO load) will participate in the Midwest ISO's Energy Markets as a result of GFA parties' voluntary election of one of the Midwest ISO's three options proposed for scheduling and financially settling GFA transactions or by voluntarily converting their service to the TEMT. Another approximately 5,000 MW

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schedules that the GFA Responsible Entity clears in the day-ahead market. The Midwest ISO will also charge the GFA Responsible Entity the cost of losses for all transactions under the GFA, then, if the GFA Scheduling Entity has timely submitted a conforming schedule for the GFA, credit back to the GFA Responsible Entity the difference between marginal losses and system losses at the GFA source and sink points. Option C requires the GFA Responsible Entity to pay the costs of congestion for all GFA transactions.

[4] 16 U.S.C. § 824e (2000).

[5] Midwest Independent Transmission System Operator, Inc., 107 FERC ¶ 61,191 (2004) (Procedural Order).

[6] *Id*. at P 3.

(4.5 percent of total MISO load), representing those GFAs for which unilateral modification is subject to the just and reasonable standard of review, will also participate in the Midwest ISO's markets pursuant to the requirements of this order. This leaves only approximately 10,385 MW (9.6 percent of total Midwest ISO load) that the Commission finds can be "carved-out" and therefore not participate in the Midwest ISO's Energy and FTR Markets, representing transmission service provided under: (1) those GFAs for which the parties have explicitly provided that unilateral modification is subject to the *Mobile-Sierra*[7] public interest standard of review; (2) those GFAs that are silent with respect to the standard of review; and (3) those GFAs providing for transmission service by an entity that is not a public utility.

5. We find that the Midwest ISO will be able to reliably operate its Energy and FTR Markets with this carve-out of GFAs given the relatively small amount of transmission service (less than 10 percent of total Midwest ISO load) involved. Moreover, we find that, even with this carve-out, the Midwest ISO's Energy and FTR Markets will be more reliable and efficient overall than the market currently in place in the region.

6. Finally, we decide upon the applicability of Schedule 16, FTR Service, and Schedule 17, Energy Market Service, to transactions taking place under GFAs. Specifically, we find that Schedule 16 charges should apply to GFA transactions to the extent that those transactions are subject to the Midwest ISO Energy Markets and GFA parties have nominated FTRs for those transactions or otherwise receive a hedge in the Day-Ahead Energy Markets for such transactions. GFA transactions would not otherwise be subject to Schedule 16 charges. With respect to Schedule 17 charges, we find that those charges should apply to all GFA transactions on the same basis that they apply to non-GFA transactions. For GFAs subject to the Midwest ISO Energy Markets, the Schedule 16 and 17 charges will be the responsibility of the GFA Responsible Entity. For carved-out GFAs, Schedule 17 charges will be the responsibility of the Transmission Owner or Independent Transmission Company (ITC) Participant taking service under the Midwest ISO Tariff to meet its transmission service obligations under the GFA.

7. Our action here will ensure that the Midwest ISO's Energy Markets start on time with the benefit of a comprehensive approach to GFAs and a clear definition of their relationship to the new Energy Markets. Today's order benefits customers by taking measures necessary to ensure that the GFA parties and other market participants are treated fairly and reasonably upon the start of the Midwest ISO's Energy Markets on March 1, 2005. We also expect that this order will provide parties to the GFAs and the

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[7] *See* United Gas Pipe Line Company v. Mobile Gas Service Corp., 350 U.S. 332 (1956) (*Mobile*); FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956) (*Sierra*).

Midwest ISO with the framework they need to begin the FTR allocation process on schedule, thereby meeting a deadline critical to an on-time start to the Energy Markets.

8. This order first addresses the issue of the impacts of GFAs on the reliability and economic efficiency of the Midwest ISO Energy Markets, followed by a discussion of the GFA sub-categories and their treatment, and then it addresses our determinations on the conversion options and the treatment of carved-out GFAs before and after the transition period. The order finishes by addressing the Midwest ISO's May 26, 2004 compliance filing proposing revisions to Attachment P (List of GFAs).

I. Background

9. By order issued September 16, 1998, the Commission conditionally approved the formation of the Midwest ISO.[8] The Formation Order also conditionally accepted for filing an open access transmission tariff (OATT) for the Midwest ISO (Midwest ISO Tariff), and an Agreement of Transmission Facilities Owners to Organize the Midwest Transmission System Operator, Inc. (Midwest ISO Agreement), and established hearing procedures. In addition, the Commission granted conditional approval for ten public utilities to transfer operational control of their jurisdictional transmission facilities to the Midwest ISO, and deferred placement under the Midwest ISO Tariff of transmission service for the Transmission Owners' bundled retail load and service provided under wholesale bilateral GFAs for six years.[9]

10. Subsequently, in an order on initial decision resulting from the hearing, the Commission found that the Midwest ISO must be the sole provider of transmission service over its system and required that Transmission Owners and ITC Participants take service under the Midwest ISO Tariff to serve their bundled retail load and meet their obligation under the GFAs.[10]

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[8] Midwest Independent Transmission System Operator, Inc., *et al*., 84 FERC ¶ 61,231 (Formation Order), *order on reconsideration*, 85 FERC ¶ 61,250, *order on reh'g*, 85 FERC ¶ 61,372 (1998).

[9] Formation Order at 62,167, 62,169-70. *See also* Midwest ISO Agreement at Appendix C.II.A.1.f.

[10] Midwest Independent Transmission System Operator, Inc., *et al*., Opinion No. 453, 97 FERC ¶ 61,033 at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC & 61,141 (2002), *order on remand*, 102 FERC ¶ 61,192 (2003), *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom.* Midwest ISO Transmission Owners, *et al*. v.

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11. On December 20, 2001, the Commission found that the Midwest ISO's proposal to become a Regional Transmission Organization (RTO) satisfied the requirements of Order No. 2000,[11] and thus granted the Midwest ISO RTO status.[12] The Commission also determined that the Midwest ISO's proposal for congestion management was a reasonable initial approach to managing congestion that satisfied the requirements of Order No. 2000 for Day 1 operation of an RTO, but directed it to develop a market-based approach to manage congestion to satisfy the requirements for Day 2 operations under Order No. 2000.

12. Subsequently, the Midwest ISO filed a petition for declaratory order – the culmination of over a year of stakeholder discussions[13] – that sought the Commission's endorsement of the general approach represented in three proposed market rules (Market Rules). The Market Rules proposed in the filing would provide for: (1) a security-constrained, centralized bid-based scheduling and dispatch system (*i.e.*, day-ahead and real-time market rules); (2) FTRs for hedging congestion costs; and (3) market settlement rules. The Commission approved the general direction of the Midwest ISO's proposals, reserving judgment on some issues and providing guidance on others.[14] The Commission affirmed many of its conclusions on rehearing.[15]

13. On July 25, 2003, the Midwest ISO filed a proposed TEMT pursuant to section 205 of the FPA (July 25 Filing). Like the March 31 Filing, the July 25 Filing included

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FERC, 373 F.3d 1361 (D.C. Cir. 2004).

[11] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (2000), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[12] Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 (2001) (RTO Order), *reh'g denied*, 103 FERC ¶ 61,169 (2003).

[13] *See* Doying testimony at 4.

[14] Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,196 (2003) (Declaratory Order).

[15] Midwest Independent Transmission System Operator, Inc., 103 FERC ¶ 61,210 (2003).

terms and conditions necessary to implement a Day-Ahead Energy Market, Real-Time Energy Market, and FTRs. The July 25 Filing met with numerous protests, many of which alleged that the filing was incomplete and premature. Following a stakeholder vote, the Midwest ISO filed a motion to withdraw the proposed TEMT, but it requested "any and all guidance the Commission can give the Midwest ISO and its stakeholders on the matters presented in the July 25th Filing."[16]

14. The Commission granted the Midwest ISO's motion to withdraw the July 25 Filing and provided, on an advisory basis, guidance on a number of issues raised in that filing.[17] The Commission stated in the TEMT I Order that it expected its guidance to better enable the Midwest ISO to prepare and file a complete version of the TEMT or a similar proposal. The Commission instructed the Midwest ISO to include five elements in its revised Energy Markets filing: (1) a *pro forma* System Support Resource Agreement; (2) a marginal loss crediting mechanism; (3) a methodology for initial FTR allocations; (4) creditworthiness provisions; and (5) market mitigation measures.

15. The Midwest ISO filed a revised TEMT on March 31, 2004 (March 31 Filing), raising an issue that will be important to the operation of the proposed Energy Markets. The Midwest ISO stated in its transmittal letter, and through the testimony of two witnesses, that it would be unable to operate its Energy Markets without integrating an estimated 300 pre-OATT GFAs that are currently effective in the Midwest ISO region. It also concluded that up to 40,000 megawatts of transmission service – about 40 percent of total load in the region[18] – is likely to be associated with the GFAs.[19] The Midwest ISO

[16] Motion to Withdraw Without Prejudice the July 25 Energy Markets Tariff Filing at 5, Docket No. ER03-1118-000 (Oct. 17, 2003).

[17] Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,145 (2003) (TEMT I Order), *reh'g dismissed*, 105 FERC ¶ 61,272 (2003).

[18] The Midwest ISO stated that, after reviewing all of the contracts listed in Attachment P of the OATT, the specific details of the contracts, such as usage, scheduling requirements and megawatt quantity or capacity, were not readily apparent on the face of some of the contracts. The Midwest ISO added, however, that about half the contracts had a specific megawatt value associated with them, and that in the aggregate those contracts accounted for approximately 20,000 megawatts of capacity. The Midwest ISO projected that the remaining half of the GFAs were likely to be associated with a similar number of megawatts.

[19] The Midwest ISO's analysis assumed a peak capacity of 97,000 megawatts. *See* Dr. Ronald D. McNamara, Vice President of Regulatory Affairs and Chief Economist of

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argued that allowing holders of GFAs scheduling rights similar to their current practice would require a physical reservation, or carve-out, of transmission capacity in the Day-Ahead Energy Market and until the scheduling deadline prior to real-time dispatch. It stated that this "cannot be accomplished without negatively impacting the Midwest ISO's ability to reliably operate the Energy Markets and without placing excessive financial burden on other Market Participants."[20]

16. The Procedural Order gave an initial response to the threshold GFA issue. The Commission explained that "the development of the Midwest ISO as an RTO has reached a point at which the Commission must examine the potential conflict between our desire to preserve the GFAs and our instructions that the Midwest ISO should develop a market-based system of congestion management."[21] The Commission identified a need for further information about the GFAs and a desire to better understand how the GFAs and the proposed Energy Markets would affect one another. Accordingly, the Commission initiated an investigation, under section 206 of the FPA, of the GFAs "to decide whether GFA operations can be coordinated with energy market operations, whether and to what extent the [Transmission Owners] should bear the costs of taking service to fulfill the existing contracts and whether and to what extent the GFAs should be modified."[22]

17. As described below, the Commission ordered GFA parties to file interpretations of their contracts in Stage 1 of the investigation, and established trial-type hearing procedures, before administrative law judges (presiding judges) – Stage 2 of the investigation – to elicit the GFA information from those parties who were not able to agree in Stage 1. The Commission also offered GFA holders an opportunity to settle their GFAs by voluntarily accepting the GFA treatment that the Midwest ISO proposed in the TEMT.

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the Midwest ISO, testimony at 84 n.5.

[20] March 31 Filing at 9.

[21] Procedural Order at P 65. *See also* Declaratory Order at P 29-32, 64 ("We continue to believe that customers under existing contracts, both real or implicit, should continue to receive the same level and quality of service under a standard market design."); Declaratory Order Rehearing at P 27-31; *cf.* TEMT I Order at P 22 (encouraging the Midwest ISO to resubmit its Energy Markets proposal).

[22] Procedural Order at P 67.

18. Stage 2 of the Commission's investigation of the GFAs concluded on July 28, 2004, with the presiding judges' oral presentation to the Commission of the results of the hearing they held to elicit GFA information that was outstanding after Stage 1 and the issuance of their written Findings of Fact.[23] As outlined in the Procedural Order (and below), the instant order considers all the evidence developed in Stages 1 and 2 of the section 206 investigation to decide how GFAs should be treated in the Midwest ISO's Energy Markets.[24]

19. Finally, on August 6, 2004, the Commission issued an order approving the Midwest ISO's proposal.[25] The Commission accepted and suspended the proposed TEMT and permitted it to become effective March 1, 2005, subject to conditions and further orders on GFAs and Schedules 16 and 17 of the Midwest ISO Tariff.[26] The Commission also accepted certain tariff sheets to be effective on August 6, 2004, subject to conditions and further order on GFAs. In order to address the Midwest ISO's unique features, such as the fact that it does not have prior 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 confidence-building protections for wholesale customers during startup and transition to fully-functioning Day 2 Energy Markets in 2005.

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[23] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 63,013 (2004) (Findings of Fact).

[24] *Id*. at P 78.

[25] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,163 (2004) (TEMT II Order).

[26] Schedule 16 provides for a deferral of costs related to the development and implementation of the system and processes required to administer FTRs and the recovery of those deferred costs and the costs related to the ongoing administration of FTRs. Schedule 17 provides for a deferral of start-up costs related to the establishment of energy markets and recovery of such deferred costs and the ongoing costs of providing Energy Markets Service once the markets are operational.

II. Discussion

A. Procedural Matters

20. Parties filed numerous comments in multiple stages in this proceeding regarding the Midwest ISO's proposed TEMT. The comments relevant to this stage of the proceeding are listed in Appendix A to this order. First, parties filed interventions, comments, and protests responding to the Midwest ISO's March 31 Filing on or before May 7, 2004 (May Comments). Second, on or before June 25, 2004, parties filed comments in response to paragraph 74 of the Procedural Order regarding the effects of GFAs in the Midwest ISO's Energy Markets (June Comments). Third, on or before July 16, 2004, parties filed comments responding to the June Comments (Reply Comments). Fourth, on or before July 16, 2004, parties filed comments responding to the Midwest ISO's and its Independent Market Monitor's (IMM), Potomac Economics, economic and reliability analysis (Analysis Comments).[27] Finally, parties filed briefs on exceptions to the presiding judges' Findings of Fact on August 17, 2004.[28]

B. Economic and Reliability Analysis

21. To assist the Commission in determining whether to modify GFAs that were not settled, we directed the Midwest ISO to provide evidence on three related issues, by June 25, 2004, concerning the reliability and economic benefits of the Midwest ISO's congestion management system with GFAs included in the market.[29] First, the Commission directed the Midwest ISO and its IMM, Potomac Economics, to submit evidence of the historical reliability impact of North American Electric Reliability

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[27] As discussed below, the Procedural Order instructed the Midwest ISO and its IMM to file economic and reliability analysis of GFAs in the market by June 25, 2004. Procedural Order at P 72-73.

[28] On August 20, 2004, Consumers filed a brief opposing Detroit Edison's exceptions. Per the Procedural Order, which stated that "[b]riefs opposing exceptions will not be allowed," we will not accept Consumers' brief opposing exceptions. *See* Procedural Order at P 76. In addition, on September 7, 2004, Detroit Edison filed a motion to reject Consumers' brief opposing exceptions and, in the alternative, a response to Consumers' brief. In light of our rejection of Consumers' brief opposing exceptions, we will also reject Detroit Edison's response.

[29] *Id*. at P 72.

Council (NERC) Transmission Line-Loading Relief (TLR)[30] procedures in the Midwest ISO region. Second, the Commission directed the Midwest ISO to submit evidence that examines in detail how a carve-out of the GFAs would impede the reliability of the proposed Day 2 Energy Markets.[31] Third, the Commission directed the Midwest ISO to file information on the economic impacts of TLRs in its region and the quantifiable benefits of the proposed congestion management system, focusing on how a carve-out of the GFAs would impede these costs savings.[32] Parties were given an opportunity to comment on the Midwest ISO's analysis.[33]

22. The Commission also sought comments from all affected parties on: (1) whether keeping the GFAs separate from the market would negatively impact reliability; (2) the extent to which accommodating GFAs would shift costs to third parties; and (3) whether keeping the GFAs separate from the market would result in undue discrimination. Parties were given an opportunity to submit reply comments.[34]

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[30] According to NERC TLR procedures, in the event that curtailments are required to reduce power flows on constrained flowgates below operation security limits, the transmission operator cuts all transactions that impact the constrained flowgate by more than the five percent threshold in order of the relevant service priorities. Within each service priority, transactions with impacts above the 5 percent threshold are curtailed on a pro-rata basis. The nature of power systems is such that operators cannot curtail only the portion of the power flow from each transaction that affects the constrained flowgate; rather, the entire transaction must be curtailed.

[31] Procedural Order at 72.

[32] *Id*. at P 73. The Commission directed the Midwest ISO to include all workpapers and assumptions supporting its quantification of the economic benefits of the proposed congestion management system as it applied to the GFAs.

[33] By notice issued June 18, 2004, the Commission allowed initial comments to be filed on July 16, 2004.

[34] By notice issued June 18, 2004, the Commission allowed reply comments regarding the three issues enumerated above to be filed on July 16, 2004.

1. **Midwest ISO and IMM Data and Analysis**

23. On June 25, 2004, the Midwest ISO submitted testimony in its Compliance Filing[35] to the Commission on the reliability and economic impacts of the Midwest ISO's congestion management system with and without accommodation of GFAs in their current form and the IMM submitted an analysis of TLR procedures. The Midwest ISO estimated a $713.1 million annual benefit from congestion management, or $586.1 million net of energy market costs.

24. In its Compliance Filing, the Midwest ISO explains that, of the contracts it reviewed, approximately half had a specific megawatt value associated with the contract. These contracts in the aggregate accounted for approximately 20,000 MW of capacity.[36] Based on this analysis, the Midwest ISO estimates a total of 40,000 MW associated with all of the GFAs, as noted in the Procedural Order.[37] With respect to reliability impacts, the Midwest ISO makes several points predicated upon the estimated 40,000 MW cutout. First, according to Dr. McNamara, a physical carve-out from the actual dispatch is not possible. He asserts that it is physically impossible to ignore or treat separately the electrical energy associated with GFAs (or any other bilateral contract) when arranging dispatch and coordinating real-time power flows.

25. Second, Dr. McNamara explains that allowing a carve-out from the scheduling timelines in the TEMT for GFAs impacts reliability. To the extent that the GFAs allow for more flexibility in the scheduling than is allowed in the TEMT, the Midwest ISO will have to estimate the generation and load from the GFAs in order to commit sufficient units to ensure reliability. Without direct GFA scheduling data, these estimates will invariably be less accurate than the information the GFA parties themselves would be capable of providing under the TEMT.

26. Third, Dr. McNamara states that the introduction of a regional security-constrained economic dispatch (SCED) will improve reliability in the Midwest ISO footprint. Changing from local control area dispatch in conjunction with TLR procedures to regionalized 5-minute dispatch will lead to more precise management of transmission

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[35] Midwest ISO June 25, 2004 Compliance Filing at 2. Analysis of Summary Results addressed in the testimony of Dr. Ronald D. McNamara, Vice President of Regulatory Affairs and Chief Economist.

[36] *See* McNamara testimony at 61.

[37] Procedural Order at P 16.

constraints and will improve the reliability of the network. A carve-out for GFAs would undermine both reliability and economic benefits by removing incentives for GFA parties to schedule efficiently and participate in a regional SCED.

27. To provide background, Dr. McNamara explains that, under current operations, the Midwest ISO, in its role as Reliability Coordinator, does not dispatch generation. The existing method for managing congestion relies on reserving and scheduling estimated Available Flowgate Capacity (AFC) and, when not all scheduled service requests can be physically accommodated, curtailing transmission service under TLR procedures - in essence, physically rationing transmission capacity based on priorities related to firmness and length of service with economic redispatch of intra-control area transactions being performed by each of many small control areas. Like other physical rationing mechanisms, according to Dr. McNamara, the current approach contains inherent inefficiencies due to under-utilization of assets and the inability to optimize asset utilization based on prices and economic value.[38]

28. Current system operations, states Dr. McNamara, will be replaced with a process in which much of system operations and the all-important function of generation dispatch and related reliability functions will be performed or coordinated at the regional level by the Midwest ISO under the TEMT. According to Dr. McNamara, the Midwest ISO is now functioning as Reliability Coordinator for its footprint and has already assumed some regional coordination functions associated with reliability, which include operating the Midwest ISO Open-Access Same-Time Information System (OASIS) and processing requests for transmission reservations, scheduling inter-control area transactions, and managing use of the TLR curtailment process for congestion that is not managed by local area dispatches. However, asserts Dr. McNamara, some of these current responsibilities will change somewhat under the proposed TEMT, wherein the Midwest ISO will assume responsibility for operating a regional SCED (which will replace TLRs) to relieve congestion.[39]

29. Dr. McNamara analyzes the effect of replacing TLRs with a regional SCED to relieve congestion and concludes that a SCED system will be a substantial improvement in the overall reliability of the grid. However, for this improvement to occur, Dr. McNamara explains that the security-constrained economic dispatch must be coordinated

[38] *See* McNamara testimony at 48.

[39] *Id*. at 5 and 6.

at the regional level, not the local control area level, to capture the fact that loop flows are a broad regional phenomenon, not just a local issue.[40]

30. Dr. McNamara states that reliance on TLRs for congestion management inherently leaves transmission capacity under-utilized because the TLR approach relies on imprecise flow estimates and cannot accurately reflect system interactions. Further, explains Dr. McNamara, the Reliability Coordinator calling the TLRs cannot know how long each of the scheduling parties will take to implement the requested curtailments. The amount of congestion relief achievable from the TLR approach, according to Dr. McNamara, is therefore imprecise and somewhat unpredictable. He states that the Regional Reliability Coordinator that calls the TLR cannot accurately predict how much relief the constrained grid will realize through each TLR curtailment, and therefore may curtail too many or too few transactions in each TLR event.

31. Moreover, he explains, TLRs are issued to curtail specific transmission transactions. When a transaction is curtailed, the affected control areas must then redispatch generation, curtail load or reconfigure their systems to comply and maintain balance. Each of these actions, according to Dr. McNamara, takes time and occurs within constantly changing levels and patterns of load, generation and power flows.

32. The Midwest ISO's analysis of TLR events in its region during 2003 found that reliance on TLRs for congestion management makes it more difficult to maintain power flows within operating security limits. Actual or post-contingency power flows violated security limits at some point in 556 of the 926 TLR events studied. The total time spent in violation of the security limits equaled 2,163 out of the total of 10,820 hours or 20 percent of the duration of the 926 TLRs studied. While most of the excursions above the security limits were for limited periods and within the emergency limits of the affected transmission facilities, the fact that they occurred at all reflects the inherent difficulty in relying on TLRs to protect system reliability.[41]

33. The IMM also analyzed the impact of TLRs, and agreed with the Midwest ISO that there are significant uncertainties in the TLR process. The IMM states these uncertainties can affect reliability and the system operators' ability to fully utilize the system. Because of these uncertainties, conservative assumptions must be used to

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[40] *Id*. at 8-10.

[41] *Id*. at 44-45.

schedule transmission service and operate the system. Even operating the system in a conservative manner, explains the IMM, there are still periods when the flows exceed the operating limits because the TLRs invoked do not provide the full amount of relief anticipated for the transmission constraint. According to the IMM, the central dispatch that occurs in an LMP market increases the RTO's control over network flows. When flows do approach the limit, the LMP market will quickly and effectively redispatch generation to prevent the flows from exceeding the limit. It is the opinion of the IMM that the uncertainties and imprecision that are inherent in the current TLR regime result in the Midwest ISO having less control of the network flows. When these flows exceed the operating security limits for a transmission facility or flowgate, one may conclude that the TLR procedures have contributed to a lower level of reliability than would exist under the proposed LMP markets, states the IMM.

34. The IMM conducted an analysis of TLR events in the Midwest ISO in calendar-year 2003 that showed that 39 percent of the TLR curtailments are accurate, with over-curtailments or under-curtailments of less than 1 percent of the flowgate limit. These results, states the IMM, are encouraging considering the uncertainties inherent in the TLR processs. However, in the opinion of the IMM, reliability concerns associated with the TLR process are raised by the instances of under-curtailments when the flow is greater than the flowgate limit by more than 1 percent. The IMM's analysis shows that this occurred in 16 percent of the hours when TLRs were invoked. The IMM contends that implementation of centralized dispatch would eliminate these instances as generation is redispatched continuously to maintain network flows at or below the transmission limits.

35. To answer the second question in the Procedural Order (evidence that examines in detail how a carve-out of the GFAs would impede the reliability of the proposed Day 2 markets), Dr. McNamara begins by defining the term "carve-out." According to Dr. McNamara, the Procedural Order sometimes spoke of a "carve-out from the market" and other times indicates that the carve-out has something to do with physical scheduling requirements. However, because dispatch and use of the real-time market are the same thing, explains Dr. McNamara, it is not meaningful to consider concepts that assume that GFA schedules could be handled "outside the market." Dr. McNamara states that because all schedules, all injections and all withdrawals are using exactly the same grid, *all* schedules and grid uses affect flows on the grid and all schedules must be accounted for in the system operator's security-constrained economic dispatch. He states that the flows from all schedules and grid uses determine the degree and location of congestion and thus affect the need for, and the costs of, congestion redispatch. Hence, according to Dr. McNamara, there is no meaningful way in which GFA schedules can be carved-out without affecting the market and the market prices faced by third parties. In this sense, he concludes, the very concept of a carve-out is problematic.

36. Furthermore, Dr. McNamara considers the notion of a "physical" carve-out to be incompatible with the requirements for a reliable dispatch. Dr. McNamara cites to Dr. Hogan's March 31, 2004 testimony discussing GFA treatment, in which Dr. Hogan made clear that a total physical carve-out of all possible grid usages that could occur under the many GFAs is simply not workable. Dr. Hogan emphasized, and the Commission noted in its Procedural Order, that the grid operator must know the net injections and net withdrawals, by location, of each grid usage, in order to arrange a security-constrained economic dispatch. Dr. Hogan noted that this information is, of necessity, today provided to the local entities responsible for grid operations and so must be provided to the Midwest ISO when it takes over the same grid operation functions, such as a regional security-constrained economic dispatch. Dr. Hogan concluded that all grid users, including parties to GFA transactions, must provide to the Midwest ISO the same information on each schedule's net injections and net withdrawals and must do so within the same time deadlines that apply to all proposed grid usage.

37. Assuming that the definition of "carve-out" means that GFA schedules could be exempt from these most basic requirements for maintaining reliable operations, Dr. McNamara explains that the Midwest ISO would have to accommodate GFA schedules no matter when they were submitted, no matter what the net injections or net withdrawals were and no matter what locations were affected, up to the limits defined in the GFAs.

38. Further, according to Dr. McNamara, carving out GFAs in this way would mean that GFA parties would not participate in any way in five major enhancements the Midwest ISO is bringing to the region in the TEMT. The first enhancement he lists includes a regional security-constrained economic dispatch, and the availability of this dispatch to replace the use of TLRs. Dr. McNamara states that a carve-out could mean that GFA schedules would need to be subject to the same degree of TLRs as they are now, and that the Midwest ISO would not offer or provide redispatch to support GFA schedules if they would otherwise have been subject to TLRs. Nor, Dr. McNamara posits, would GFA parties be allowed to purchase and pay for this redispatch service, even if redispatch was available and more economic than TLRs. The Midwest ISO would instead impose TLRs on the GFA schedules to the extent TLRs would have been used in the absence of the ISO's regional dispatch.

39. A second enhancement that Dr. McNamara lists is the ability to use the real-time balancing market to provide and price imbalances and to buy and sell energy. GFA parties would, instead, according to Dr. McNamara, obtain balancing service from the local control areas under the restrictions and penalties that apply today. Dr. McNamara states that other enhancements that GFAs would be unable to use include: the ability to use the day-ahead energy market to lock-in energy and transmission prices in advance; the use of LMP prices for imbalances and spot market sales and purchases, and the use of

LMP-based usage charges to price transmission usage and congestion redispatch; and, the ability to be compensated for counterflows that help relieve congestion.

40. If, according to Dr. McNamara, it is assumed that a carve-out means that the GFA schedules were not subject to the same scheduling deadlines and net injection and withdrawal data requirements as other grid users, and not subject to LMP-based energy and usage charges in either the day-ahead or real-time markets, then the Midwest ISO would still need to account for the capacity likely to be used by GFA schedules when they were finally submitted. In the day-ahead energy market, according to Dr. McNamara, assuming GFA schedules would not be submitted by the day-ahead scheduling deadline, the Midwest ISO would be required to make its own estimates of GFA schedules. Because GFA schedules would not be subject to the LMP price signals that encourage behavior consistent with reliability, there would be no incentives for GFA parties to take actions consistent with reliable dispatch – there would be no incentive for the GFA parties to participate in the day-ahead market, so the Midwest ISO could not get any advance indication on how the grid would be used in real time other than its own guesses of expected GFA transmission usage.

41. In response to the Procedural Order, the Midwest ISO performed this analysis at congested flowgates during 2003 in three areas: (1) the Mid-Continent Area Power Pool (MAPP) footprint; (2) the Wisconsin Upper Michigan System (WUMS) sub-region; and, (3) the rest of the Midwest ISO. The study found the under-utilization of transmission capacity during Level 3 and higher TLR events averaged 16.4 percent in the MAPP footprint, 10.9 percent in the WUMS sub-region, and 7.7 percent in the remainder of the Midwest ISO for 2003. The average unused capacity for the entire Midwest ISO region during all TLR events studied was 12.9 percent. In short, the study found that the grid was persistently under-used because of the imprecision and uncertainty of the TLR approach.

42. Accordingly, Dr. McNamara concludes that reliance on TLRs results in economic inefficiency. Under NERC TLR procedures, he states, when a curtailment is needed, all transactions in the selected service priority (gradations of firm and non-firm service) that impact the constrained flowgate by more than the minimum (5 percent) threshold are cut on a *pro-rata* basis. However, Dr. McNamara points out, the economic value of the curtailed transactions never enters into the *pro-rata* allocation of TLR curtailments. Moreover, he contends, as redispatch is neither offered nor priced, there is no mechanism by which the parties that are subject to TLR curtailments can determine whether it would be more economic to pay for redispatch in lieu of curtailment or to accept curtailment.

43. In the absence of a real-time price signal, explains Dr. McNamara, it is not possible to determine the economic impact of curtailing any particular transaction, nor is it possible to compare the marginal cost of redispatching generation to the economic

value of the transactions that are curtailed by TLRs. Thus, he concludes, it will often be the case that the costs of implementing a TLR greatly exceed the cost of a comparatively small economic redispatch that could provide the same reduction in flows over the constrained flowgate. For these reasons, Dr. McNamara believes that it is highly unlikely that the grid can be efficiently used under a TLR approach.[42]

44. The IMM agrees that TLR procedures are inefficient because they make no attempt to optimize the curtailments (*i.e*., to redispatch the generation with the largest effect on the flowgate at least cost). In addition, states the IMM, the TLR curtailments themselves are subject to limited resolution in both time (they are essentially hourly) and space (transaction source and sinks are modeled at the control area level versus node or bus). With regard to the timing of the TLR calls, Reliability Coordinators are required to make decisions on TLR curtailments based on a combination of real-time information, forecasts of future flows, and the inherent lags in the participant's actions (including the permitted lag on the ramping of curtailed transactions), according to the IMM.

45. In contrast, according to Dr. McNamara, the proposed TEMT will provide for more efficient congestion management. Dr. McNamara considers a primary objective of the TEMT to be reliable, economic, and nondiscriminatory unit commitment and dispatch to efficiently manage transmission congestion. Once the dispatch is arranged, he argues, the proven way to encourage generators to follow dispatch instructions is through the use of LMP. Dr. McNamara posits that the proposed real-time and day-ahead energy markets are the means to secure price bids to facilitate coordinated unit commitment and security-constrained economic dispatch.

46. To evaluate these conclusions, the Midwest ISO conducted an analysis of the economic impact of TLRs and the benefits of the congestion management system reflected in the proposed TEMT. According to Dr. McNamara, the analysis determined the net economic benefits from the perspective of the cost of power at market prices moving from the current system of rationing transmission capacity and TLRs to the proposed system of congestion management. Looking at the cost of power at market prices, states Dr. McNamara, Midwest ISO members are likely to realize net economic benefits from implementation of the proposed TEMT of approximately $586.1 million per year. This reflects $713.1 million per year in savings from lower market prices for power in the Midwest ISO region. To calculate the net savings, explains Dr. McNamara, the amount of the benefit was offset by $127.0 million per year in fees to cover the implementation and operation of the proposed markets. The average load zone market-clearing price of power in the Midwest ISO footprint is forecast to be lower under the

[42] *Id*. at 12-15.

Midwest ISO TEMT by $1.18 per MWH. On a monthly basis, average price per MWH savings range from $0.46 in April to $1.94 for July. As explained by Dr. McNamara, the reduction in the load-weighted average market price was multiplied by Midwest ISO load to calculate the reduction in the market cost of power given the improved efficiencies from the proposed system of congestion management.

47. Dr. McNamara explains that the analysis also determined the net economic benefits, from a cost-of-service perspective, of moving from the current system of rationing transmission capacity and TLRs to the proposed system of congestion management. From a cost-of-service perspective, Midwest ISO members are likely to realize net economic benefits from implementation of the proposed TEMT of approximately $128.4 million per year, according to Dr. McNamara. This reflects $255.3 million per year in net savings from reduced generation and purchased power costs and increased revenues from off-system sales to parties outside the Midwest ISO footprint. This amount is offset by an estimated $127.0 million per year in fees to cover the implementation and operation of the proposed markets. Looking at the overall Midwest ISO footprint from a cost of service perspective, states Dr. McNamara, the savings are largely the result of lower prices for purchased power and an increase in both power imports to and exports from, Midwest ISO member companies. Total power purchases by Midwest ISO member companies from non-Midwest ISO generators are estimated to increase in the proposed market by 4.9 million MWH per year under the proposed TEMT. However, according to Dr. McNamara, despite the increased imports, coordinated unit commitment and dispatch can be expected to reduce market-clearing prices such that the average price paid for power imports would fall by an average of $2.74 per MWH, or 9.1 percent. The reduction in market clearing prices for such purchases is forecasted to result in a savings of $98.7 million per year, offsetting most of the impact of an increase in the volume of purchases. Additionally, power sales from Midwest ISO to non-Midwest ISO entities are expected to increase by 10.8 million MWH per year given the proposed Midwest ISO energy markets. The increase in revenues from sales to entities outside of the Midwest ISO of $282 million per year, less the cost of increased power purchases from others, (which, given lower prices in the Midwest ISO, equals $36.4 million), results in a net benefit to Midwest ISO members from off-system sales and purchases of $245.6 million per year, according to the study results.

48. Additionally, explains Dr. McNamara, total generation costs in the region are forecasted to decline by $9.7 million per year given the proposed system of congestion management. This is a calculation of net savings after taking into consideration the cost of generating an additional 5.8 million MWH for export.

49. The IMM also conducted an analysis to determine the benefits of the system for congestion management under the proposed TEMT compared to the current regime based

on TLRs. The likely differences in the outcomes of the TLR procedures versus the economic dispatch process resulting from an LMP market was evaluated by the IMM through a comparison of the results of the TLR process to a simulated redispatch of generation to manage the same congestion. This analysis, for the 2003 period, showed that the TLR process, on average, curtails more than three times more megawatts than would be necessary to achieve the same result through economic dispatch. It also shows that for individual flowgates, the TLR curtailments ranged from 73 percent more than the redispatch amount to 472 percent more (almost six times the redispatch amount).

50. With respect to the economic impacts of carving-out GFAs, Dr. McNamara notes that when the carved-out GFA schedules are finally submitted closer to real time, real-time congestion would likely be greater and the Midwest ISO would incur greater congestion redispatch costs in the real-time dispatch. Because the carved-out GFA schedules would not have to pay the marginal costs of redispatch for congestion imposed by their own schedules, the GFA parties would not have any incentives to schedule efficiently or to choose wisely between alternative generation that might limit redispatch costs. In contrast, non-GFA parties who deviate from their day-ahead schedules would have to pay these increased congestion costs. In addition, while non-GFA parties who had followed their day-ahead schedules in real time would, under the proposed TEMT, not have to pay for increased congestion in the real-time market for their own transmission schedules, because they would already have purchased transmission for those schedules at day-ahead usage prices, they would still be exposed to the unhedgeable risks of real-time congestion costs because non-GFA parties, not the carved-out GFA parties, would have to pay the uplift for the unrecovered costs of congestion redispatch required in real time. Thus, this carve-out would result in additional costs for third parties.

51. To assess the economic impact of a GFA carve-out, the Midwest ISO developed an illustrative case using Power World's Simulator Optimal Power Flow model applied to Wisconsin and the surrounding control areas. The model is a power flow analysis tool that automatically identifies economically optimal redispatch in response to transmission constraints. It also calculates LMPs associated with that dispatch. In this case, the Midwest ISO simulated economically optimal power flows and calculated the resulting prices with and without a physical carve-out for known GFA reservations. To represent a physical carve-out, the Midwest ISO constructed the model to simulate what would happen if GFAs were scheduled as they always have, without taking advantage of more economic dispatch solutions through the Midwest ISO's proposed markets. The results showed significant observed differences in average load zone prices for the July peak hour for which the model simulated physically accommodating known GFA reservations. The inclusion of a physical representation of known GFA reservations in the model increased transmission congestion and average prices in the Wisconsin Public Service

load zone by 52.1 percent, from $143.60 to $218.35 per MWH; for Wisconsin Power and Light by 20.9 percent, from $133.15 to $161.02 per MWH; for Upper Peninsula Power by 11.2 percent, from $138.65 to $154.18 per MWH; and for WE Energies by 5.1 percent, from $133.86 to $140.73 per MWH.

52. According to Dr. McNamara, the illustrative findings strongly suggest that carving out GFAs in a manner that avoids exposure of the GFA parties to the economic benefits of regional economic dispatch and LMP's efficient price incentives could significantly raise peak hour prices (and probably non-peak prices as well) for all parties in the region. The impact of these higher prices, he states, would be felt by both non-GFA and GFA parties alike. Non-GFA parties, Dr. McNamara concludes, could face higher LMPs and possibly higher LMP-based transmission usage charges because with less generation available for dispatch, the marginal cost of redispatch would be higher than it would be with more generators participating. Dr. McNamara also notes that the findings suggest that a carve-out would force GFA suppliers to incur higher costs in meeting their load obligations than they would incur if they participated in the regional dispatch. These higher costs, explains Dr. McNamara, represent lost opportunity costs to the suppliers and potentially lost opportunity costs to the GFA loads to the extent their contracts allowed them to capture some of the potential savings.

53. Dr. McNamara also explains that, given the difficulty that the Midwest ISO may have in anticipating post-day ahead scheduling by GFA holders, a physical carve-out, in which GFA holders are not required to schedule their transactions in advance or pay imbalance charges, has the potential to create a significant artificial divergence between day-ahead and real-time prices. Consistent and significant price divergence has the potential to undermine the value of the day-ahead market.[43]

54. Finally, with respect to implementation impacts, Dr. McNamara states that it is unlikely that the Midwest ISO would be able to implement a physical carve-out in time to meet the Commission's March 1, 2005 schedule for the start of the Day 2 market. Dr. McNamara states that while it is not well understood what a physical carve-out would require, he does not believe that the Midwest ISO has enough time built into the implementation schedule to make business process and system changes to accommodate this option. Moreover, explains Dr. McNamara, even with unlimited time and expenditures, it is not clear whether the resulting market could function in a reasonable manner given the magnitude of the carve-out that might be required.[44]

[43] McNamara testimony at 65-70.

[44] *Id*. at 65.

2. <u>Parties' Comments on Economic and Reliability Analysis</u>

(a) <u>Comments in Response to the Midwest ISO and IMM's Evidence and Analysis</u>

55. On July 16, 2004, the Michigan/Kentucky Parties, LG&E, Detroit Edison, the Midwest ISO TOs, the Midwest TDUs, and the Rural Electric Cooperatives filed comments on the Midwest ISO and IMM's reliability and economic impacts analysis.[45]

56. The Michigan/Kentucky Parties comment that the Commission should establish hearing procedures, subjecting the Midwest ISO's and IMM's analysis to cross-examination, because allowing parties only the opportunity to comment does not fulfill the Commission's constitutional due process obligation. They also urge the Commission to consider the ramifications of proceeding on the basis of the untested, uncorroborated assertions of the Midwest ISO. With respect to the IMM's analysis, the Michigan/Kentucky Parties assert that, to the extent the analysis relies upon presumed LMP market operations, it lacks a sound evidentiary basis because, at this point, the proposed LMP-based congestion management system has not yet been implemented and the design is incomplete. They state that, in its analysis, the IMM even admits that it has not conducted studies of TLRs and reliability "per se." The Michigan/Kentucky Parties assert that, rather than conducting a study of TLRs and reliability, the IMM's analysis consists of a comparison of historical TLR calls and the presumed impact of a "simulated" redispatch of generation under LMP, and that is a baseless assertion.

57. The Michigan/Kentucky Parties also claim that the Midwest ISO's analysis failed to quantify the benefits of its proposed congestion management system and to adequately analyze the impact of GFAs on the proposed market. Specifically, they argue that the Midwest ISO's analysis is flawed because it failed to provide workpapers, account for GFA rights, and quantify the impact of alleged GFA interference and cost shifts. They state that the Midwest ISO incorrectly presumes all GFAs' present scheduling limitations and ignores that any potential scheduling limitations can be overcome without abrogating or modifying GFAs. The Michigan/Kentucky Parties point out that, rather than figuring out a way to make a carve-out approach work, the Midwest ISO simply states that it does not have the time to build such an exercise into its schedule. Finally, the Michigan/Kentucky Parties argue that the Midwest ISO incorrectly and unfairly tags GFAs as the root of all congestion problems.

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[45] As stated above, Appendix A to this order lists the various parties who filed comments in this proceeding.

58. The Midwest ISO TOs also raise several concerns regarding the Midwest ISO's analysis stating that they do not accept the Midwest ISO's studies as to the costs associated with carving out GFAs and arguing that there has not been enough time to evaluate the reasonableness of the study. As to the Midwest ISO's TLR study, the Midwest ISO TOs argue that it would be necessary to test all of the assumptions and models used to determine whether or not the results are valid and that has not been, and cannot be, done without the opportunity for discovery concerning the model and data used by Dr. McNamara. The Midwest ISO TOs also point to their June Comments, where they proposed to provide GFA parties with two additional alternatives, stating that nothing filed by the Midwest ISO affects the validity of their proposed alternatives.

59. Detroit Edison also submitted comments in response to the Midwest ISO's analysis, requesting that the Commission require the Midwest ISO to complete a more thorough analysis of any impacts that honoring GFAs may have on reliability. It states that the Midwest ISO's conclusions with regard to how a carve-out of GFAs would impede reliability of the proposed Day 2 markets are wholly unsupported and that the Midwest ISO fails to quantify the impacts of honoring GFAs. Detroit Edison also asserts that the Midwest ISO's primary concern is the time that it would take to determine whether honoring GFAs would impact reliability.

60. The Rural Electric Cooperatives contend that the Midwest ISO's estimate of the megawatt magnitude of the transmission services associated with the GFAs is speculative. Thus, they submit the testimony of Stephen P. Daniel, which they contend illustrates that the Midwest ISO overstates the current and future magnitude of the GFA issue and fails to support the need to abrogate GFAs. The Rural Electric Cooperatives also contend that the Midwest ISO's calculation regarding the benefits of implementing LMP is questionable because: (1) the estimate is a single-year snapshot that is not necessarily indicative of the future as conditions change; (2) the estimate is likely within the margin of error of the model used; (3) from the limited information presented, it appears that the model used by the Midwest ISO is more akin to a Midwest ISO regional economic dispatch model based on costs rather than a bid-based LMP market as proposed in the TEMT; and (4) since the Midwest ISO did not submit all of its workpapers and assumptions supporting its quantification of benefits, and given the tight constraints of this proceeding, it is impossible to fully verify or challenge the Midwest ISO's analysis.

61. With respect to reliability, the Rural Electric Cooperatives assert that the Midwest ISO's analysis of purported reliability impacts is based solely on economic theory related to increased grid utilization, and is not a factual, or even reliability-driven analysis. They explain that the debate of the merits of TLRs versus LMP is not germane to the GFA reliability impacts issue because TLRs will still be necessary, even in organized markets using LMP (as evidenced in PJM, New York, and New England), in order to maintain

reliability. Further, the Rural Electric Cooperatives assert that the information filed by the Midwest ISO's IMM does not relate to reliability, but to purported efficiencies that might be achieved by replacing TLRs with LMP markets, suppositions about increased utilization of the grid that LMP markets would allow as compared to TLRs, and unsupported allegations that central dispatch as utilized in an LMP market would increase the RTO's control over network flows.

62. The Midwest TDUs contend that the Midwest ISO's cost-benefit study suffers from at least seven fundamental flaws in that it: (1) is opaque, to the point of non-compliance (because the Midwest ISO did not submit all of its workpapers and assumptions supporting its quantification of benefits); (2) reflects, as vastly understated, the markets' cost because it only considers projected spending by the Midwest ISO itself; (3) ignores seams between the Midwest ISO and its neighbors in its treatment of flowgates; (4) unrealistically derates internal and external flowgates; (5) ignores the potential exercise of market power because it assumes that each generator will be bid and dispatched at its marginal cost; (6) lacks sufficient justification for the hurdle rates used in the analysis; and (7) fails to account for the fact that LMP-based markets impose costly risks on their participants.

63. Additionally, the Midwest TDUs argue that the Midwest ISO's other arguments for overriding GFAs, that do not focus on the cost-benefit calculus, also fail. They state that while the Midwest ISO argues that application of the TEMT to GFAs is needed to enable it to "see" the sources and sinks associated with intra-control-area GFA schedules, it is far from obvious that the Midwest ISO needs all of its proposed changes to GFA arrangements to accomplish such visibility. The Midwest TDUs also argue that the Midwest ISO can not disregard the Standard Market Design White Paper[46] commitment to protect the economics of both GFAs and other existing long-term firm transactions when it asserts that the three options it proposes for GFAs could increase costs to third parties as compared to eliminating GFA treatment.[47] Further, in response to the Midwest ISO and certain generator-oriented stakeholders' assertion that the Midwest ISO's options might hold GFA parties better than harmless and suggestion that those options should be curtailed, the Midwest TDUs state that any finding of unjust enrichment would be baseless.

[46] Remedying Undue Discrimination through Open Access Transmission Service and Standard Market Design, Notice of White Paper, Docket No. RM01-12-000 (Apr. 28, 2003).

[47] *See* Midwest TDU's Analysis Comments at 12.

64. LG&E submitted a protest to the Midwest ISO's June 25 filing, asking the Commission to reject the Midwest ISO's analysis and, to the extent that the Commission accepts the filing, establish an evidentiary hearing to examine the economic and reliability benefits of the Day 2 market and the potential cost shifts associated with Options A, B, and C for GFA treatment. LG&E also argues that the Midwest ISO fails to justify its criticism of TLRs or its advancement of its congestion management proposal.

(b) <u>June Comments Generally Supporting GFA Carve-Out</u>

65. Pursuant to P 74 of the Procedural Order, on June 25, 2004, the parties listed in Appendix A to this order filed comments on the impact of accommodating GFAs in the market. Detroit Edison, Hoosier, the Michigan/Kentucky Parties, the Midwest ISO TOs, AECC, Corn Belt, Montana-Dakota, TVA, and the Rural Electric Cooperatives generally believe that exclusion of the GFAs from the Midwest ISO Energy Markets would not impact reliability, shift costs to third parties, or result in undue discrimination.

66. Specifically, Detroit Edison asserts that keeping the GFAs separate from the market would not negatively impact reliability, pointing out that other regions have honored GFAs without a noticeable impact on the reliable operation of the transmission system. For example, it argues that "phantom congestion" due to grandfathered agreements in the California ISO (CAISO) did not jeopardize the reliability of the CAISO's transmission system. Detroit Edison also comments that the Commission must balance any cost shift to third parties by recognizing the cost shift to GFA parties that will occur if they are forced to reform or abandon their previously approved contracts. Further, Detriot Edison comments that contracts that were previously approved by the Commission should not be deemed unduly discriminatory by virtue of an energy markets platform that the Commission has not fully explored and is in the process of refining.

67. According to the Michigan/Kentucky Parties, eradicating or reshaping GFAs to accommodate a market that does not exist and that has not been approved is contrary to established law. They state that the legal presumption is in favor of upholding the GFAs and that the Midwest ISO should bear the burden of establishing a *prima facie* case establishing GFA reliability concerns. They argue that the Commission should set the matter for hearing and investigation to afford interested parties their due process rights. The Michigan/Kentucky Parties explain that if the GFAs are incompatible with the market, then the market must be reshaped or rejected. They assert that the Commission and the Midwest ISO were aware of the GFAs prior to the Midwest ISO's formation, which would not exist unless the Midwest ISO Agreement, requiring the Midwest ISO to honor GFAs, came into effect. Further, the Michigan/Kentucky Parties state that reliability of the transmission grid does not hinge on the existence of GFAs alone and that inquiry into this factor will prove useless. They also note that GFAs do not shift costs to third parties because no third party is being asked to pay any portion of any payment due

from one party to another under any GFA. Finally, they argue that different treatment does not equate to undue discrimination.

68. The Midwest ISO TOs explain that there are no reliability or economic issues preventing a carve-out of the GFAs from the Midwest ISO markets, especially if the solution they propose is implemented. The Midwest ISO TOs assert that central to the compromise that led to the voluntary formation of the Midwest ISO was that the GFAs would not be disturbed during the six-year transition period and to break this understanding would hinder future development of RTOs and ISOs.

69. With regard to reliability, the Midwest ISO TOs state that while advance notice of system conditions aid a system operator's ability to manage reliability, the day-ahead market is a financial market and does not provide all of the necessary information required to ensure reliability in real time. They argue that reliability does not hinge on load scheduling in this market and that market participants are not even required to schedule load in the day-ahead market. With respect to cost shifting, the Midwest ISO TOs assert that based on prior Commission decisions, GFA loads are already subject to Schedule 10 charges under the Midwest ISO Tariff, which covers a large portion of Midwest ISO's infrastructure costs. The Midwest ISO TOs also contend that under well-established case precedent, the existence of differing rates, terms, and conditions due to the existence of contracts executed at different times has repeatedly been found by the courts not to constitute undue discrimination.

70. Hoosier comments that it is both a GFA customer and a GFA provider of service. As a GFA customer, Hoosier joins in the Midwest ISO TO's comments. In its role as a GFA service provider, Hoosier argues that because it is not a public utility under the FPA, it is not subject to the jurisdiction of the Commission and thus, the Commission cannot modify Hoosier's GFA contracts. Regardless, Hoosier states that the continued implementation of its GFAs will not negatively impact reliability, or result in cost shifting or undue discrimination. Hoosier explains that because its contracts will not contribute significantly to increased congestion, costs related to congestion management will not be diverted to third parties as a result of keeping its GFAs separate.

71. TVA comments that there would be no negative impact on reliability from keeping the two GFAs to which it is a party separate from the Midwest ISO market. TVA suggests that notifying the Midwest ISO of day-ahead projections and real-time use information would provide sufficient information to assist the Midwest ISO in assessing the capability and reliability of the system. TVA also asserts that forcing GFA transactions to participate in the market would be unduly discriminatory and would unfairly shift costs of running the Midwest ISO market from Midwest ISO members who regularly use those markets, to those GFA parties who need only transmission service under their GFAs.

72. Montana-Dakota states that maintenance of the GFAs to which Montana-Dakota is a party will not have a material adverse impact on implementation of the TEMT. It asserts that regardless of the manner in which the GFAs of other Midwest ISO participants might be treated, the Commission should respect its prior determination to accord special treatment to the GFAs to which Montana-Dakota is a party until February 1, 2008. Further, Montana-Dakota states that keeping GFAs separate from the market would not shift additional costs to third parties or result in undue discrimination; however, forcing GFAs into the market would.

73. Similarly, Corn Belt asserts that the contractual terms and physical rights set forth in its GFAs should be preserved and not modified to make Corn Belt an unwilling participant in the Midwest ISO's Energy Markets. It argues that keeping the GFAs separate will not result in cost shifts to third parties or undue discrimination because any capacity available for third parties is subject to a Commission-approved OATT. Corn Belt further notes the possible legal ramifications that may result if modifications to its existing contracts are considered in conjunction with its Rural Utilities Service loan contract.

74. Rural Electric Cooperatives do not believe that a separation of the GFAs from the Midwest ISO market will impact reliability or result in an inappropriate shift of costs to non-GFA holders. Rather, they contend that the costs identified by the Midwest ISO are a consequence of the structure proposed in the TEMT rather than costs originating with the GFAs. However, Rural Electric Cooperatives stress that in order to fully comment on these issues, any dispute regarding GFAs must be resolved via the hearing process, where a larger picture of the current state of GFAs will be provided.

75. AECC argues that market designs that do not accommodate GFAs could impede, rather than accelerate, progress toward competition in wholesale markets. AECC explains that it is not located in the Midwest ISO footprint and is not a party to any GFAs, but that the outcome of these proceedings could substantially affect its pre-Order No. 888[48] agreements. It reminds the Commission that the existing transmission grid was

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[48] Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs., Regulations Preambles January 1991 - June 1996 ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs., Regulations Preambles July 1996 - December 2000 ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Study Group, *et al*. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom*. New

(continued)

designed to accommodate longstanding contract path-based arrangements, like GFAs. AECC believes that concerns about reliability can be attributed to newer, possibly beneficial, uses of the system and that it is reasonable for the Commission to ask the advocates of these new uses to accommodate the existing uses, rather than break existing contracts.

(c) June Comments Generally Opposed to a GFA Carve-Out and Other June Comments

76. Cinergy, Dynegy, and FirstEnergy generally believe that exempting GFAs from the Midwest ISO TEMT would negatively affect the Midwest ISO market, while OMS, LG&E, WPPI, WPS Resources, and the Midwest TDUs have mixed responses regarding the issue.

77. Specifically, Cinergy argues that carving out GFAs would undercut many of the reliability benefits associated with the Day 2 market as there would be greater complexities in the physical scheduling systems as well as different financial incentives for GFA and non-GFA parties. It states that exempting GFAs from the Midwest ISO TEMT would cause inefficiencies in both the energy spot market and the FTR market due to distortion of the incentives GFA transacting parties would otherwise encounter when considering participation in the Midwest ISO spot markets, resulting in sub-optimal region-wide unit commitment and dispatch. Cinergy comments that costs will be shifted to non-GFA parties who are subject to LMP and that a GFA carve-out approach would create two classes of transmission service on the shared grid, which would be unduly discriminatory.

78. Dynegy states that separating GFAs from the market will negatively affect reliability because the model used for day-ahead system security will be inaccurate. It states that in order to assure that the requisite voltage and flow are available, the Midwest ISO will have to make a conservative estimate, which will lead to the Midwest ISO using both the day-ahead and real-time Reliability Assessment Commitment to unnecessarily order on unneeded generating units. Further, it asserts that undue discrimination against non-GFA transactions will result if GFAs are carved-out, leading to an inefficient, inaccurate day-ahead dispatch with potential for under-use of system capability and preferential treatment for GFAs. Dynegy states that most entities will perform a cost/benefit analysis between joining PJM versus the Midwest ISO and that those with

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York v. FERC, 535 U.S. 1 (2002).

the ability to choose, should choose PJM for more (and more mature) markets and a known, consistent quantity/quality.

79. FirstEnergy submits that keeping the GFAs separate from the market may not negatively affect physical reliability, but will negatively affect the implementation of the Midwest ISO's proposed market-based congestion management procedure. It also states that costs will shift to third parties, but that the magnitude of these costs cannot be determined until uplift charges and FTR uses have been determined. It also asserts that keeping GFAs separate from the market will result in undue discrimination, because by allowing GFAs to participate in the Midwest ISO, customers would receive access to transmission service without paying the associated costs that all other market participants are required to pay. However, FirstEnergy states, maintaining the terms of GFAs while subjecting GFA transactions to the Energy Markets could result in Transmission Owners' incurring additional costs that they are unable to recover under the GFAs, unless the Commission reforms the GFAs.

80. WPPI contends that by separating GFAs from the market, market participants will be forced to pay uplifted congestion costs attributed to GFA transmission as well as Midwest ISO costs to administer these agreements. It argues that the TEMT would not provide long-term firm transmission customers the same protections from congestion pricing risk that it does GFAs, and hence it is discriminatory. In addition, WPPI asserts that the TEMT allows full FTR protection for some customers while denying it to others that will be subject to pro-rata reductions in the FTR allocation process even though both customer classes obtained their existing service through the same capacity reservation process. WPPI recommends that this discrimination be remedied by allowing long-term firm OATT reservations to be scheduled for physical delivery a day ahead under Option B or establishing a floor to limit FTR proration.

81. LG&E emphasizes that the proposed TEMT should be rejected and the Midwest ISO should file an amended Day 2 tariff comporting with the principles of voluntary market participation. It explains that if GFAs are carved out of the market, they will be provided greater scheduling flexibility, shifting costs to non-GFA loads. However, LG&E argues that keeping GFAs separate from the market may not necessarily impact reliability and that the Midwest ISO's continued ability to redispatch generation using the NERC TLR process will relieve any problematic constraints. LG&E states that there is no definitive evidence presented by the Midwest ISO, including Dr. Hogan's testimony that a carve-out of GFAs harms reliability. It also states that there is not enough information available to truly assess the reliability questions posed by the Procedural Order. It contends that the Midwest ISO should undertake a thorough and transparent analysis of the market impacts of GFA transactions.

82. OMS argues that separating GFAs from the Midwest ISO market will impact grid reliability if GFAs are not required to submit reasonably accurate schedules into the day-ahead market. However, if anticipated GFA use were scheduled in the day-ahead market with limited adjustments allowed in the real-time market, it would be feasible to keep GFAs separate. Nonetheless, OMS contends that GFA separation may result in undue discrimination in a variety of ways. For example, non-GFA holders will suffer discrimination due to less scheduling flexibility than GFA holders. Further, OMS states that the Midwest ISO's proposed accommodation of GFA congestion costs will result either in a shortfall of FTRs available for market participants to hedge their own congestion costs, or an uplift of congestion charges, and hence, an unfair shift of costs.

83. The Midwest TDUs contend that more information is needed before any reliability impact resulting from a GFA carve-out can be analyzed. However, they state that if it were proven that unpredictable GFA loads were locking up Midwest ISO paths, it might be appropriate to bring those GFAs into the market by encouraging or requiring day-ahead scheduling. They contend that the Midwest ISO's proposal will result in risk or cost shifting from the transmission provider, who under the GFA bears responsibility for late schedule changes, to the GFA customer, by forcing GFA transactions, to schedule sooner, bear losses differently, and pay for markets they do not use and taking from non-GFA existing transactions to the extent they do not get allocated full FTR hedges, the financial right to the energy they inject.

84. WPS Resources states that allowing the physical separation of GFAs could potentially impact grid reliability and result in unfair cost shifting. It states that allowing GFAs to participate in the Midwest ISO market, but forcing other participants to pay their costs, is also unduly discriminatory.

85. The North Dakota Commission disagrees with the Midwest ISO's distinction between the proposed treatment of GFAs and Integrated Transmission Agreements (ITAs). It asserts that non-Midwest ISO members providing service to their own non-Midwest ISO loads under ITAs with Midwest ISO members are neither participating in the Midwest ISO market nor receiving Midwest ISO transmission service and that abrogating such contracts would discourage efficient cooperation in the future.

(d) <u>Reply Comments</u>

86. On July 16, 2004, the Michigan/Kentucky Parties and the Rural Electric Cooperatives filed Reply Comments. The Michigan/Kentucky Parties argue that none of the parties who filed responses to the Commission's questions, nor any party to date, have provided any factual evidence sufficient to substantiate a claim that overrides the legal presumption in favor of honoring the terms and conditions of GFAs. Specifically, they argue that no party has: (1) presented evidence suggesting that keeping the GFAs

separate from the market would negatively impact reliability; (2) provided any quantification of the extent to which GFAs may shift costs to third parties; (3) or proffered any factual evidence to support an allegation that excluding GFAs will result in unduly discriminatory treatment. For example, the Michigan/Kentucky Parties point out that FirstEnergy admits that keeping GFAs separate from the market may not negatively affect reliability in the region. They also point out that Cinergy's comments state that GFAs must be integrated into the proposed structure to protect reliability and to capture market efficiencies, but that Cinergy mainly focuses on opposing Option B of the Midwest ISO's proposal which, the Michigan/Kentucky Parties state, is outside the scope of the Commission's narrow inquiry.

87. The Michigan/Kentucky Parties note that FirstEnergy admits that it made no effort to quantify the economic impact of carving out GFAs, and therefore, if there may be costs borne by non-GFA parties, the impact of any such alleged cost shifts is not known. Further, the Michigan/Kentucky Parties assert that, contrary to responding parties' claims, the different treatment GFAs may receive does not automatically equate to undue discrimination. Finally, they urge the Commission to engage in a forum to explore the issues involving the TEMT and to provide parties an opportunity to engage in discovery and cross-examination.

88. The Rural Electric Cooperatives also filed reply comments. They reemphasize that keeping the GFAs separate from the market would not shift costs to third parties since GFAs already exist, and are currently scheduled and operate reliably on the system, so there are no new incremental costs associated with supporting these GFA transactions. The Rural Electric Cooperatives argue that neither the Procedural Order, nor any of the other comments filed in this proceeding, explain how preserving GFAs would constitute undue discrimination under the proposed TEMT relative to non-GFA market participants.

3. Commission Discussion

89. We will not recite the analysis presented by Dr. McNamara and the IMM on how the Midwest ISO Energy Markets are managed. No party disputes these descriptions and they stand on their merits as summaries of the Midwest ISO energy market operations and they are sufficient for our purposes here. Thus, we find that, based on the evidence and analysis presented, the Midwest ISO can reliably operate the Day 2 Energy Markets with some GFAs that are carved out from TEMT scheduling, as discussed in the next section of this order. We acknowledge that a carve-out could result in inefficiencies that would result in additional costs for non-GFA transmission customers under the TEMT. However, even with a carve-out and the inefficiencies that could result, we believe that the Day 2 Energy Markets will be more reliable and efficient overall than the current Day 1 energy market.

90. We first address the reliability impacts of GFAs. The pertinent issue before the Commission is whether there are reliability impacts that result from how GFAs must be managed and scheduled by the Midwest ISO in the management and operation of its Energy Markets. "Carving out" GFAs in this context means that parties to GFAs are allowed to exercise the scheduling and energy management provisions of their GFAs in the same manner they did before the Energy Markets started.[49] We agree with Dr. McNamara that some interpretations of how to coordinate a physical carve-out with the scheduling and dispatching protocols under the TEMT might not be compatible with reliability, and hence should be excluded from consideration. As he states, parties with GFAs cannot operate "outside the market" in all senses, but must in certain respects follow the same scheduling practices as other users of the Midwest ISO system, such as specifying points of injection and withdrawal, to allow the Midwest ISO to perform its security-constrained economic dispatch (SCED) for the footprint.[50]

91. As characterized by the Midwest ISO, carved-out GFAs would not be required to schedule in the Day-Ahead Energy Market and would be allowed to submit their final physical schedules at some time just prior to real-time dispatch, and their imbalances need not be settled in the Real Time Energy Market.[51] As a consequence, the Midwest ISO would have to estimate GFA schedules in its Day-Ahead scheduling and Reliability Assessment Commitment (RAC) process that occur before the GFA schedule is submitted.[52] However, the estimation process may include some judgments on the appropriate level and spatial configuration for unit commitments, and the management of reserves. In the circumstance that the GFA carved-out schedules are incorrect, the Midwest ISO may have to obtain additional unit commitments or additional reserves in real-time, and possibly order TLRs and invoke emergency load shedding procedures. In

[49] We agree with Dr. McNamara that a physical carve out from actual dispatch is not possible. All GFA transactions must be dispatched by the Midwest ISO once they submit schedules. *See* McNamara testimony at 4.

[50] "Dispatch" refers here only to those generation units that are submitted into the Midwest ISO market and are hence dispatchable. Generation resources scheduled under GFAs will not be redispatchable, except in cases of emergency.

[51] We note that the Midwest ISO has identified that nearly 85 percent of the MW service entitlements associated with GFAs do not address scheduling or allow services without a scheduling obligation. *See* McNamara testimony at 62.

[52] *Id.* at 28.

short, accommodating GFAs into an energy market will increase the unpredictability and complexity of reliability planning for daily operations.

92. However, while we concur with the Midwest ISO that carving out GFAs presents reliability management challenges, we believe some GFAs could be accommodated with a carve out in the Energy Markets without threatening reliability for several reasons. In general, we believe that: (1) the increased scope of the Energy Market under the centralized dispatch will increase the availability of redispatch capability in the event of congestion; and (2) the measures taken to account for security constraints and other reliability requirements will enhance the ability of the system operator to anticipate and respond to reliability problems.

93. More specifically, this means that first, in the day-ahead and reliability unit commitment process, we expect that the Midwest ISO will take all steps necessary to ensure reliability of the dispatch by incorporating and evaluating GFA schedules and procuring sufficient generation capability in the reliability unit commitment and ancillary services to account for all likely circumstances.[53] Dr. McNamara confirms this conclusion when he states that the planning process for the Midwest ISO would still account for the impact of GFA schedules in its estimation process. We further note that the Midwest ISO TOs have offered to provide scheduling estimates for GFAs, as will also be discussed later in this order, thereby providing a better estimate of GFA schedules for the Midwest ISO Energy Markets.

94. Second, the real-time market, also accounting for security constraints, will provide more efficient and effective tools for managing congestion and reduce the need to resort to TLRs. The LMP-based real-time energy market will provide market participants, other than GFAs, with economic incentives to manage their energy sales, purchases and transmission use in a way that supports reliability and allocates grid use efficiently. For example, transmission usage will be priced to reflect the marginal cost of redispatching the grid to avoid security limits. Also, the SCED process, which allows the grid operator to continuously adjust generation dispatch every five minutes, ensures violations of security limits generally can be addressed before they occur.[54] Accordingly, we agree with the IMM that the SCED process will reduce TLRs.[55] Third, the small number of

[53] We recognize the negative consequence of this approach on costs, which we discuss in the economic efficiency discussion that follows.

[54] McNamara testimony at 9.

[55] *See* IMM Report at 9. We also note that Dr. Hogan draws the same conclusion. *See* Hogan testimony at 31.

GFAs that are being carved out of the Energy Markets, discussed more fully in the next section of this order, are not expected to pose a significant threat to reliability over the Midwest ISO grid.

95. Our general reliability concern is that NERC cites TLRs as a reliability threat; as we noted in our Procedural Order, when TLRs are invoked, the process by which dispatchers get back within the security limits is cumbersome and inefficient.[56] We agree with the Rural Electric Cooperatives that TLRs are a feature of other energy markets, and it is not realistic to expect they can be eliminated entirely.[57] Rather, the reliability imperative is to reduce TLRs to the extent possible, an objective we believe is achieved by centrally dispatched energy markets, including the Midwest ISO Energy Markets. We expect the Midwest ISO Energy Markets will be more reliable because of the incentives provided by the LMP market, the regional SCED process available to the Midwest ISO, and the reliability safeguards we instituted in the TEMT II Order.

96. At the same time, we recognize that there are some geographic areas that are more heavily influenced by transactions under GFAs (as well as self-scheduled transactions by non-GFA parties) than others, and therefore may require occasional resort to TLRs as a reliability management option. This circumstance would occur in the event that redispatch were required to relieve congestion and the Midwest ISO was unable to obtain sufficient redispatch capability from non-GFAs (*i.e*., there were insufficient offers into the spot market), leaving TLRs as the only remaining option.

97. To ensure that we have addressed any potential reliability impacts of GFAs, we direct the Midwest ISO to report to us in 30 days if it identifies any reliability problems that would preclude successful operation of the Midwest ISO energy markets at start-up. This report must identify the problem, provide supporting schedules that document why the market can not operate reliably, identify specific contracts contributing to the problem and explain how it intends to resolve the problem.

98. We are not concerned that the Midwest ISO has not sufficiently quantified the reliability impact of GFAs. The description of the reliability management process

[56] We note the analysis by the IMM that in 16 percent of the hours in which TLRs were called in 2003, under-curtailments occurred and that flows reached over 20 percent beyond the flowgate limit in a few instances. *See* IMM Report at 7.

[57] In this regard, we note Dr. McNamara’s statement that the TEMT may not be able to eliminate TLRs due to the lack of a mechanism to hold external transmission customers responsible for redispatch costs. *See* McNamara testimony at 21.

provided by Dr. McNamara provides the factual description needed to assess how GFAs will be managed in the Midwest ISO Energy Markets, and therefore is sufficient for our purposes. Furthermore, other energy markets have successfully accommodated GFAs at the levels envisioned here without threatening system reliability.[58]

99. Turning next to the economic impact of a carve-out, as defined above, on non-GFA parties, we recognize that a carve-out of GFAs has the potential to result in additional costs for non-GFA transactions. However, we expect those impacts to be minor, in light of the small percentage of capacity to be carved-out. First, a carve-out will require that the full MW associated with such GFAs be withheld from the FTR allocation model, thus reducing the allocation of FTRs to non-GFA parties. This could increase exposure of some parties to net positive congestion charges (after FTR revenues are accounted for), and may require the Midwest ISO to seek new ways to provide additional congestion hedges for such parties. This could raise costs for non-GFA transmission users under the Midwest ISO TEMT. Second, while the Midwest ISO TOs' proposal to submit an indicative day-ahead schedule will assist the Midwest ISO in conducting a more efficient reliability unit commitment, the Midwest ISO will still have to use judgment in determining how to evaluate GFA schedules in that commitment. This will likely result in sub-optimal unit commitment, raising the costs of the reliability unit commitment, as noted by Cinergy and Dynegy. Third, the likelihood of inefficient scheduling by GFA holders will increase the costs of energy and congestion charges to non-GFA parties, thus potentially reducing the benefits of the Midwest ISO markets relative to what they might have been. For example, generation offered into the Energy Markets could be redispatched to accommodate inefficient GFA schedules, but only non-GFA market participants will be exposed to the resulting higher LMPs.

100. While carving out GFAs will clearly have negative consequences on efficiency in the Midwest ISO Energy Markets, we disagree with the contention of the Midwest ISO, in its August 17 informational filing, that a carve-out of GFAs will threaten the viability of centralized dispatch and Energy Markets. We note that the Midwest ISO position is predicated on a carve-out of approximately 15,000 MW,[59] whereas our analysis, discussed later in this order, identifies approximately 10,385 MW of carved-out GFAs

[58] With respect to Cinergy's citation to PJM's comments (*See* Tabor testimony at 9) that express concern over potential difficulties with operating an LMP market with a very high proportion of loads under grandfathered contracts, we note that circumstance will not exist in the Midwest ISO Energy Markets where only a small percentage of loads will remain under carved-out GFAs.

[59] *See* Midwest ISO August 17, 2004 Informational Filing at 4.

which represents approximately 9.6 percent of the Midwest ISO's total peak load.[60] Given the scale and scope of the Midwest ISO Energy Markets, ample generation sources, scheduling estimation provided by the TOs, and a wide range of transmission options, we are not persuaded that a carve-out at this level would be notably detrimental to the efficient functioning of its Energy Markets during the GFA transition period.[61] Because implementing the TEMT even with a GFA carve-out will still expand the use of economic dispatch, aggregate costs under the new Day 2 markets should still be less than under the status quo Day 1 market and the overall efficiency of the market would improve.

101. Finally, we share the concerns expressed by parties that a carve-out could provide gaming incentives for GFA customers, especially those that also take service under the TEMT and therefore participate in the spot markets operated by the Midwest ISO. We agree with testimony submitted by Dr. Hogan that a GFA carve-out could create opportunities for market manipulation when GFA customers also participate in spot markets.[62] For example, day-ahead over-scheduling of GFAs to create "phantom" congestion may enhance the value of FTRs held under other network service contracts and therefore would also raise important concerns. Thus, we will require the IMM to monitor GFA customers for gaming behavior and provide an informational report to the Commission prior to the second FTR allocation. We further note that the TEMT II Order required the Midwest ISO to add Market Behavior Rule 2 to the TEMT.[63] This rule, which applies to transactions that manipulate market prices, would apply to scheduling behavior of GFAs.

[60] Midwest ISO's peak load is 107,552 MW as reported on http://www.midwestiso.org/.

[61] As discussed earlier in the order, to the extent the Midwest ISO identifies problems that preclude successful start-up and operation of its energy market, those problems must be documented in a filing within 30 days.

[62] *See* Hogan testimony at 29.

[63] *See* TEMT II Order at P 356. In the TEMT II Order, we stated that, "[i]n exercising its discretion to determine the appropriate remedy for violations of Market Behavior Rule 2 … the Commission will apply the policies and principles set forth in Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC 61,218, *clarified*, 105 FERC ¶ 61,277 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004), and subsequent relevant precedent." *Id*. at P 356 n. 222.

102. We do not believe that any purpose would be served by the Midwest ISO submitting additional workpapers or holding further hearings, as some parties request. The analysis of the impacts of GFAs submitted by the Midwest ISO and its IMM and the accompanying explanations of their methods and assumptions are sufficient for our purposes here.

C. Analysis of the Midwest ISO Grandfathered Agreements

1. Background of Three-Step Fact-Finding Investigation

103. As stated above, in the Procedural Order, the Commission initiated a three-step investigation of the GFAs under section 206 of the FPA. The first step of the analysis required jurisdictional public utilities providing or taking service under GFAs (and invited any non-jurisdictional parties on a voluntary basis) to submit, on or before June 25, 2004, the following GFA information to the Commission: (1) the name of the GFA Responsible Entity, as defined in the proposed TEMT; (2) the name of the GFA Scheduling Entity, as defined in the proposed TEMT; (3) the source point(s) applicable to the GFA; (4) the sink point(s) applicable to the GFA; (5) the maximum number of megawatts transmitted pursuant to the GFA for each set of source and sink points; and (6) whether modification to the GFA is subject to a "just and reasonable" standard of review or a *Mobile-Sierra*[64] "public interest" standard of review.[65]

104. The Commission also stated that, if the parties to each GFA were able to agree on the GFA information, they should file the GFA information jointly and that the Commission would evaluate these joint filings as a group to help determine the effects of the GFAs on the proposed Energy Markets. If parties to a particular GFA or GFAs were not able to agree on the GFA information, then the Commission required each party to file its own interpretation of the GFA and proceed to Step 2 of the Commission's analysis.

105. Additionally, the Commission strongly encouraged GFA party settlements and stated that it would be receptive to GFA parties voluntarily agreeing, in settlement, to accept one of the Midwest ISO's proposed scheduling and settlement options, including

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[64] *See* United Gas Pipe Line Company v. Mobile Gas Service Corp., 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Company (*Sierra*), 350 U.S. 348 (1956).

[65] By notice issued June 22, 2004, the Commission issued instructions to all parties for filing their GFA information and a template for filing summary GFA information.

Option B, for treatment of GFA transactions, or to convert their contracts to TEMT service.[66] The parties were directed to make a simple statement in their joint filings to indicate whether or not they were willing to voluntarily convert their contract to TEMT service or settle their GFA by accepting the Midwest ISO's proposed treatment of GFAs.[67] The Commission also stated that, if the Commission approved a settlement, it did not intend to later revisit its decision when it addressed the non-settling parties' GFAs.[68] Parties that did not settle their GFAs before July 27, 2004, would be subject to the Commission's analysis of how the GFAs should be treated in the Day 2 Energy Markets.[69]

106. In Step 2 of the analysis, the Commission considered all GFA information on which parties could not agree to be disputed issues of material fact and set such GFAs for hearing before two administrative law judges. The sole purpose of the hearing was to identify GFA information for every GFA on which the parties had not agreed by June 25, 2004.[70] The Commission required the presiding judges to issue written findings, and to present these written findings at the Commission meeting on July 28, 2004, on the same six informational GFA criteria required in Step 1 of our analysis.[71]

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[66] Procedural Order at P 80. The Commission stated that the GFA scheduling and settlement treatment options, including Option B, as drafted in the Midwest ISO proposal, would be available to GFA parties that jointly provided GFA information to the Commission in Step 1 (or prior to the conclusion of Step 2) of our three-step analysis, and that jointly indicated that they would accept this treatment. *Id*. at P 82.

[67] *Id*. at P 69

[68] *Id*. at P 80.

[69] *Id.* at P 78.

[70] The Commission held that hearing proceedings would begin on June 28, 2004, and terminate on July 23, 2004.

[71] Procedural Order at P 76. In the event that GFA parties reached an agreement on their GFA information prior to the conclusion of the Step 2 proceeding, they were directed to seek the presiding judges' permission to withdraw from the hearing. If the presiding judges granted permission, the parties were required to make a joint filing with the Commission as described in Step 1. Parties could voluntarily agree to convert or settle their GFAs in this filing no later than July 27, 2004, the day before the presiding judges' report issued. *Id*. at P 77.

107. In Step 3 of the analysis, following the presiding judges' oral presentation, the Commission stated that it would use the GFA information, and the other information and comments submitted in Step 1, to determine in a subsequent order (*i.e*., the instant order): (1) whether the GFAs can function as written within the proposed Energy Markets; (2) whether the GFAs can function within the Energy Markets under the Midwest ISO's proposed treatment (which the Commission retains the right to amend); or (3) whether modifications to the GFAs should be required.[72]

108. On June 25, 2004, the Commission received numerous filings in Docket Nos. ER04-691-000 and EL04-104-000, including joint filings with templates and pre-filed testimony with exhibits.[73] At the June 28, 2004 hearing, the presiding judges informed the parties of the status of their filings under each contract, and noted that many joint filings contained insufficient responses under the six categories of GFA information.[74] On June 29, 2004, the presiding judges issued an order stating that those parties whose filings contained insufficient GFA information should contact the Secretary's Office to correct the deficiencies.[75] They also stated that those joint filings asserting that the contracts at issue did not belong in this proceeding should remain subject to Step 2 of the proceeding, pending issuance of a further order addressing those GFAs. On July 1, 2004, the presiding judges issued an order directing certain parties who had agreed with the Midwest ISO that their contracts should not be considered GFAs subject to the hearing to file a motion to withdraw on that basis.[76]

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[72] *Id*. at 78.

[73] Between June 23, 2004 – June 25, 2004, by the end of Step 1, 245 template filings and 255 other filings were submitted to the Commission, totaling 500 filings. Between June 25, 2004 – July 23, 2004, by the end of Step 2, there were 125 template filings and 242 other filings submitted to the Commission, totaling 367 filings.

[74] The hearing was conducted on June 28, 29, 30 and July 1, 8, 13, 16, and 20, 2004.

[75] Order Addressing Joint Filings in Docket Nos. ER04-691-000 and EL04-104-000, (June 29, 2004).

[76] Order Confirming Rulings in Docket Nos. ER04-691-000 and EL04-104-000 (July 1, 2004).

109. On July 2, 2004, the Commission issued an order directing certain incomplete joint filings involving GFAs to be included in the on-going Step 2 hearing.[77] Specifically, the Commission found that some parties failed to supply the requested data, failed to clearly specify the relationship between the services reported for each GFA so as to avoid double counting of services, or left undetermined whether modification to the GFA is subject to a "just and reasonable" standard of review or a *Mobile-Sierra* "public interest" standard of review. The Commission also directed that certain joint filings requesting that the associated GFAs be excluded from the proceeding remain in the hearing in order to: (1) establish the data required by the Procedural Order, to the extent that they are deficient; or (2) give the parties an opportunity to establish that the service provided under the GFA is such that it will not impact operation of Midwest ISO's Energy Markets.[78]

110. On July 6, 2004, the presiding judges ordered those parties whose joint filings were deemed deficient to file amended joint filings curing the deficiencies no later than July 9, 2004, or to appear on July 13, 2004 prepared to present their direct cases on those GFAs.[79] Those parties who jointly filed requests to be excluded from the proceedings were ordered to file motions to withdraw by July 9, 2004. The parties were directed to provide in their motions reasons for the request and establish that the service provided under the GFAs will not impact the operation of the Midwest ISO Energy Markets.

111. During the course of the Step 2 proceedings, the presiding judges continued to evaluate joint filings to ascertain whether the GFAs should be withdrawn or included in the Step 2 proceedings, or whether further information was required to make such a preliminary determination.[80] The presiding judges also issued orders granting motions to withdraw certain GFAs, and various other GFAs were added to the proceeding during the

[77] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,006 at P 10 (2004) (July 2 Order). Attachment A to the order contained a list of GFAs for which joint filings had been found to contain one or more deficiencies.

[78] *Id*. at P 16.

[79] Order Establishing Further Procedures and Ruling on Joint Stipulation Regarding GFA No. 111 in Docket Nos. ER04-691-000 and EL01-104-000 (July 6, 2004).

[80] At the hearing on July 8, 2004 and in a subsequent electronic communication, the parties were given contact information for non-decisional Commission staff members who provided individual counseling to the parties.

process. In addition, in conformance with the guidelines listed in the Commission's July 2 Order, the presiding judges and non-decisional staff[81] continued to work with the parties that filed joint templates in Step 1 (*i.e.*, parties that were not explicitly directed to participate in the Step 2 hearing) to further improve their jointly-filed information.[82]

112. On July 21, 2004, the presiding judges issued an order terminating Step 2 proceedings with respect to certain GFAs with cured template deficiencies.[83] Orders terminating Step 2 proceedings were also issued on July 22, 2004[84] and July 23, 2004,[85] regarding other GFAs.

2. <u>Presiding Judges' Findings of Fact</u>

113. On July 28, 2004, the presiding judges presented their Findings of Fact in this proceeding to the Commission at its open meeting and issued written Findings of Fact.[86] The presiding judges found that a total of 450 GFAs were identified in Steps 1 and 2, and that 235 of those should be excluded from this proceeding, as they did not provide transmission service or were otherwise outside the scope of the Commission's inquiry. Of the 215 contracts that remained, the presiding judges found that the parties to 152, or 71 percent, filed joint answers to all six of the Commission's questions, indicating that they agreed on the GFA information the Commission had sought in the Procedural Order.

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[81] By notices issued May 6, 2004 and June 8, 2004, the Commission designated a total of six members of its decisional staff as non-decisional employees and non-decisional authorities for purposes of these dockets.

[82] Findings of Fact at P 32.

[83] Order Requiring Further Submission of Evidence, Docket Nos. ER04-691-000 and EL04-104-000 (July 21, 2004).

[84] Order Terminating Step 2 Proceedings With Respect to Certain GFAs with Cured Template Deficiencies, Docket Nos. ER04-69l-000 and EL04-04-000 (July 22, 2004).

[85] Order Terminating Step 2 Proceedings With Respect to Certain GFAs with Cured Template Deficiencies, Docket Nos. ER04-69l-000 and EL04-104-000 (July 23, 2004).

[86] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 63,013 (2004) (Findings of Fact).

The parties to 91 of these 152 contracts reached agreement on the GFA information in Step 1 of the proceeding; the parties to 61 of these contracts reached agreement in Step 2 of the proceeding. The presiding judges determined the GFA information of 52 more contracts (24 percent of the total included in the investigation).[87] They also found that the Commission received no filings for 11 contracts (5 percent of the total), as the parties are not public utilities under section 201 of the FPA[88] and chose not to voluntarily submit information. During Steps 1 and 2, a total of 52 parties settled their contracts by mutually agreeing to accept one of the TEMT options for GFA treatment. Those parties chose Option A, Option B, a combination of Options A and B for their initial treatment upon the commencement of Midwest ISO's Energy Markets or chose to convert the transmission service under their contract to service under the transmission and energy markets provisions of the TEMT.

114. In their Findings of Fact, the presiding judges stated that, in accordance with the July 2 Order, they had evaluated for sufficiency: (1) the numerous revised joint filings that parties made to cure deficiencies in their initial filings; and (2) the joint templates of parties who came to agreement during the hearing on all GFA information.[89] The presiding judges also stated that they had evaluated for sufficiency the data in filings associated with contracts that were added during the proceeding.[90] In addition, the judges stated that they had interpreted the July 2 Order expansively in order to provide the best record possible to the Commission.[91]

115. As discussed more fully below, the presiding judges made determinations with respect to the Step 2 GFAs, including findings regarding the appropriate GFA

[87] The 52 disputed contracts that proceeded to Step 2 for hearing included: GFA Nos. 205, 206, 207, 215, 220, 221, 267, 268, 269, 273/311, 274/320, 284, 293, 297, 300, 302, 304, 306, 308, 309, 313, 314, 316, 317, 321, 352, 354, 360, 361,364, 365, 374, 377, 389, 391, 409, 410, 411, 415, 431, 432, 433, 434, 435, 436, 437, 438, 439, 440, and 450.

[88] 16 U.S.C. § 824 (2000).

[89] *See* Findings of Fact at P 30.

[90] The judges explained that this information is in a database that was created for this proceeding and is available for the Commission's use in the Office of Markets, Tariffs and Rates. Public versions of these records were appended to the Findings of Fact as Attachment A. *See id.*

[91] *Id*. at P 32.

Responsible Entity, GFA Scheduling Entity, and the appropriate standard of review for modifications to the GFAs.

116. As pertinent here, regarding the presiding judges' determination of the appropriate standard of review for contract modification, *i.e*., whether modification to a GFA is subject to the "just and reasonable" standard of review or the *Mobile-Sierra* public interest standard of review, the presiding judges permitted parties that could not agree on the applicable standard of review to supplement the record by filing legal memoranda in support of the appropriate standard of review.[92]

117. The presiding judges explained that, under the *Mobile-Sierra* doctrine, "the Commission is permitted to exercise its rate-making authority to abrogate private contracts that are subject to a 'public interest' standard where the public interest 'imperatively demands' such action."[93] Correspondingly, they further explained that, under the public interest standard, the Commission may enforce the terms and conditions of a contract even if they are unjust and unreasonable. The presiding judges asserted that this standard differs from the just and reasonable standard, which simply reflects that all rates, terms and conditions be just and reasonable. As a result, the public interest standard is more difficult to meet than the just and reasonable standard.[94]

118. The presiding judges ultimately held that in cases where the GFA does not contain any explicit language providing the parties with unilateral filing rights, the applicable standard of review for modifications initiated by the parties would be the *Mobile-Sierra* public interest standard of review. However, if that contract also did not contain language that limited the Commission's ability to modify the contract, the presiding judges found that any changes initiated by the Commission would be subject to the just and reasonable standard of review.[95]

119. On August 17, 2004 the parties listed in Appendix A to this order filed briefs on exceptions to the presiding judge's July 28, 2004 Findings of Fact. The parties raised numerous issues, including, among other things, exceptions with respect to the presiding

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[92] *Id*. at P 41.

[93] *Id*. at P 43 (*citing* Metropolitan Edison Co. v. FERC, 595 F.2d 851, 856 n.29 (D.C. Cir. 1979)).

[94] Findings of Fact at P 44.

[95] *Id*. at P 47.

judges' findings on the GFA Responsible Entity, GFA Scheduling Entity and appropriate legal standard, as discussed more fully below.

3. Parties' Comments on GFA Modification

(a) May Comments Regarding GFA Modification

120. In their May Comments on the Midwest ISO's proposed TEMT, the Midwest ISO TOs state that the Midwest ISO effectively seeks to revise existing contracts without the appropriate legal requirements being satisfied, or it is seeking to impose charges on public utilities to those GFAs without those utilities having a reasonable opportunity to recover the costs. They believe that the Midwest ISO has failed to make the necessary showing under the *Mobile-Sierra* doctrine that revision of the existing contracts meets the public interest standard. Further, the Midwest ISO TOs state that there is no operational reason that the Midwest ISO cannot operate by excluding the GFAs, much as PJM operates its market. The Midwest ISO TOs state that they are willing to provide the Midwest ISO with the operational information that it needs in order to implement the market with a carve-out for the GFAs that would hold the GFAs harmless from any market-related costs and charges.

121. The Midwest ISO TOs are primarily concerned that the Midwest ISO's proposed options for treatment of GFAs under the TEMT will lead to trapped costs and unlawful modification of contracts. Under the Midwest ISO's proposed options, GFAs may be exposed to congestion and marginal loss costs associated with schedule changes, uplift to cover congestion and losses revenue shortfalls, and Schedule 16 and 17 costs. The Midwest ISO TOs state that there is currently no method for recovery of such costs in the GFAs, so the costs will become trapped. Therefore, they recommend that the Commission reject the Midwest ISO's proposal for treatment of GFAs.

122. Montana-Dakota argues that the Midwest ISO's GFA proposal will impose additional costs without yielding additional benefits. Montana-Dakota asserts that it is unjust to permit the imposition of additional costs that cannot be passed through to the customers that cause the costs to be incurred. Therefore, it urges the Commission to require the Midwest ISO to leave all GFAs in their original state by treating them like non-Midwest ISO load. Accordingly, Montana-Dakota argues that section 38.8 of the TEMT should be removed from the tariff, leaving GFAs intact.

123. In its May Comments, Dairyland argues against Commission acceptance of the three options for GFA treatment proposed in the TEMT. It argues that the options abrogate existing contracts by not preserving their original terms in regards to congestion and losses. Crescent Moon Utilities argue that the Midwest ISO's proposal is

unacceptable because it represents an unlawful attempt to extend the TEMT's jurisdiction to Crescent Moon's non-jurisdictional contracts.

124. WPS Resources argues that the Midwest ISO's proposal to allow GFA parties to identify the quantity and quality of grandfathered transmission services, that are not obvious in the contract, will allow GFA parties to capture more valuable FTRs or recover more congestion revenues than are appropriate. As a result, WPS Resources asks that contracts with ambiguous critical terms not be granted GFA status.

(b) June and Reply Comments Regarding GFA Modification

125. In their June Comments, the Midwest ISO TOs also reiterate their concern that the Midwest ISO is seeking to take actions contrary to the Midwest ISO Agreement. These actions include seeking to impose additional costs associated with GFAs through their options proposal and not preserving the GFAs for at least the transition period ending in 2008. They state that by accepting changes to the GFAs, in particular assigning them additional costs associated with congestion and losses, the Commission is sending a signal to the industry that it cannot rely on the initial orders in RTO/ISO formation. They extrapolate that transmission owners that are reluctant to join an RTO will become more so if the Commission changes the provisions in the Midwest ISO Agreement on which the Midwest ISO TOs based earlier decisions.

126. The Midwest ISO TOs dispute Dr. Hogan's testimony at 14, describing his "next best" solution to full conversion to TEMT service. They reiterate that if the Transmission Owner is obligated to pay the costs of the TEMT, but the GFA does not provide for a pass-through of those costs, the Transmission Owner cannot recover its costs and those costs will become essentially "trapped." The Midwest ISO TOs assert that this violates longstanding precedent to afford utilities the opportunity to recover prudently incurred costs.[96] Instead, they request that the Commission adopt their proposal to provide day-ahead scheduling information for energy flows pursuant to GFAs in exchange for carving GFA transactions out of the market, including exempting GFA transactions from Schedule 16 and 17 charges.

127. According to OMS, it is possible to carve-out GFA transactions by allowing settlements of energy to include both the real-time load and real-time generation used to serve that load via GFAs. The party responsible for scheduling energy under the GFA would need to indicate anticipated GFA use in the day-ahead schedule, but would be

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[96] Midwest ISO TOs' June Comments at 13 (*citing* FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)).

allowed to make adjustments to the schedule prior to the real-time market. OMS warns, however, that limitations to the amount of adjustments allowed must be made to preserve system reliability.

128. OMS contends that exempting GFAs from the scheduling requirements of the TEMT would be discriminatory because it would allow some participants to adjust their schedules between the day-ahead and real-time markets while others could not. However, OMS asserts that whether the discrimination is undue depends on the impact such a carve-out will have. Moreover, OMS argues that the energy imbalance market is not a major issue when dealing with GFAs as long as buyers are not forced to schedule their loads and pay imbalance charges. OMS believes that allowing substitute loss calculations for each GFA contract will have an economic impact on the pool of dollars available to refund to third-party market participants. OMS argues that it would be unduly discriminatory to allow the loss provisions of the GFA contracts to substitute for the Midwest ISO calculations.

4. Discussion Regarding GFAs That Did Not Settle

129. The Commission's three-step analysis of the GFAs was intended, among other things, to ascertain the effects of the Energy Markets on the GFAs, and the effect of the GFAs on the Energy Markets. As part of the investigation, the Commission offered the parties to the GFAs an opportunity to settle on the GFA treatment that the Midwest ISO proposed in the TEMT. A major benefit of the settlement option was to make the mutual impacts of the GFAs and the Energy Markets immediately apparent to the Commission and the parties. A total of 52 parties settled GFAs representing 9,728.5 MW by either electing one of the proposed treatment options or by agreeing to convert their contracts to TEMT service.

130. Our analysis of the information submitted by the parties to the remaining GFAs indicates, in sum, that: (a) 50 GFAs, representing 4,992.7 MW, have not settled and are subject to a just and reasonable standard of review; (b) 77 GFAs, representing 6,914.4 MW, have not settled and the parties have explicitly provided that the *Mobile-Sierra* public interest standard of review applies; (c) 20 GFAs, representing 1,272.9 MW have not settled, are disputed as to the standard of review, and the GFA is silent as to the standard of review; and (d) the entity providing transmission service under 30 GFAs, representing 2,198 MW, is not a public utility under the FPA. Consequently, the proper treatment of GFAs representing only 15,378 MW, or only 14.3 percent of the Midwest ISO's peak capacity, remains in dispute. The Midwest ISO's March 31 Filing, in contrast, originally sought modification of contracts representing more than 2½ times that much capacity. We are pleased that the parties and the presiding judges were able to resolve such a significant amount of the contracts. Reducing the magnitude of what is carved-out will minimize the operational problems such contracts create.

131. In accordance with Opinion Nos. 453 and 453-A, the Midwest ISO Tariff requires Transmission Owners and ITC Participants to take network or point-to-point service pursuant to a service agreement under the Midwest ISO Tariff in order to meet their transmission service obligations under the GFAs.[97] This is consistent with the Commission's requirement that an RTO have operational authority for all transmission facilities under its control.[98] Transmission Owners and ITC Participants that take service under the Midwest ISO Tariff for GFA transactions are not required to pay charges under Schedules 1 through 9 to the Midwest ISO Tariff, and they are not responsible for losses under Attachment M of the Midwest ISO Tariff, but they must pay Schedule 10 charges for service they take for delivery to load located within the Midwest ISO footprint.[99] When it required the Midwest ISO to assess Schedule 10 charges for all GFA load located inside the Midwest ISO, the Commission reasoned that all users of the grid operated by the Midwest ISO "benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability . . . ."[100] The court upheld the application of Schedule 10 charges for load served under GFAs,[101] although the rates, terms and conditions of GFAs themselves are honored throughout the six-year transition period.

132. As discussed above, there are many benefits associated with the Day 2 markets that the Midwest ISO has proposed. The Midwest ISO asserted, and the Commission concurs, that bulk power markets with centralized dispatch facilitate more efficient operation of the transmission system and increase transmission system reliability.[102] All users of the transmission system, including parties to GFAs, will share in these benefits.

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[97] Midwest Independent Transmission System Operator, Inc., *et al*., Opinion No. 453, 97 FERC ¶ 61,033 at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand*, 102 FERC ¶ 61,192 (2003), *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom.* Midwest ISO Transmission Owners, *et al*. v. FERC, No. 02-1121, *et al*. (D.C. Cir. July 16, 2004). *See also* Midwest ISO Tariff at section 37.1.

[98] *See* 18 C.F.R. § 35.34(j)(3) (2004); Opinion No. 453 at 61,169-70; Opinion No. 453-A at 61,411; Order No. 2000 at 31,086-107.

[99] *See* Midwest ISO Tariff at section 37.3.

[100] *See* Opinion No. 453 at 61,169.

[101] *See* Midwest ISO Transmission Owners, *et al*. v. FERC, 373 F.3d 1361, 1367-69 (D.C. Cir. 2004).

[102] *See* TEMT II Order at P 62.

133. There are new rules for operation and settlement of the Midwest ISO's new Energy Markets, and the new rules differ significantly from the service currently provided under the GFAs and the Midwest ISO Tariff. Non-grandfathered transactions, as discussed in the TEMT II Order, will be placed under the TEMT and will become subject to the new scheduling and settlement procedures. As discussed above, if all of the GFAs remain in effect without modification or accommodation, the Midwest ISO will be required to operate with multiple scheduling procedures and added complexity in its settlement procedures. This could lessen the gain in both efficiency and reliability expected to result from the Day 2 markets. The Midwest ISO therefore proposes to change its relationship to the GFA parties when the Day 2 markets are implemented.

134. Specifically, the Midwest ISO proposes to account for the operational differences between the TEMT and the GFAs by requiring parties to GFAs to select one of three options for how their GFA should be treated in the Day 2 markets. The three options, which the Midwest ISO calls Option A, Option B and Option C, essentially modify the rates, terms, and conditions of service that Transmission Owners and ITC Participants take under the Midwest ISO Tariff to meet their GFA obligations.[103] Other parties have proposed carving the GFAs out of the Energy Markets and letting the contracts continue without requiring the Transmission Owners and ITC Participants, or their counterparties under the GFAs, to accept the responsibilities associated with the TEMT, for the interim period until 2008.

135. As described in the Procedural Order, we have used the results of Steps 1 and 2 of the investigation in this docket to determine the proper treatment of the GFAs during the transition period. We have examined: (1) the information that GFA parties submitted for each contract; (2) the analysis and written comments submitted regarding the impact of GFAs on the Energy Markets, and the Energy Markets on the GFAs; (3) the presiding judges' conclusions as reported in their Findings of Fact; and (4) the Briefs on Exceptions thereto. As explained further below, we distinguish four categories of GFAs that did not agree to settle on the treatment proposed by the Midwest ISO. These categories are: (1) GFAs subject to the just and reasonable standard of review; (2) GFAs where the parties have explicitly provided that the *Mobile-Sierra* public interest standard of review applies; (3) GFAs that are silent on the standard of review; and (4) GFAs under which the entity

[103] For example, the Midwest ISO's proposed Option B, which it expected the majority of GFA parties to elect, would require the Scheduling Entity for a GFA to submit a day-ahead schedule or incur charges for congestion and losses. This is not currently required under the OATT. *See infra* Section D of this order (describing Options A, B and C).

providing service is not a public utility. We will require the Midwest ISO to integrate the first group of GFAs into the Energy Markets and to carve out the latter three groups, *i.e.*, not require that the terms and conditions of the TEMT apply to transactions under this latter group of GFAs.

(a) GFAs Subject to the Just and Reasonable Standard of Review

136. The Midwest ISO TOs and other commenters are concerned that accepting the Midwest ISO's proposed treatment of GFAs in the Energy Markets is tantamount to revising the GFAs and will lead to trapped costs. The Midwest ISO, as described above, argues that, with an estimated 40,000 MW of capacity covered by GFAs, it will be unable to reliably operate the Energy Markets if the GFAs do not participate.

137. In order to balance the Midwest ISO TOs' concerns that the Midwest ISO's proposed treatment of GFAs will lead to trapped costs with the Midwest ISO's concern that leaving GFAs intact will negatively impact reliability, the Commission finds that it is unjust and unreasonable to allow GFAs that are subject to a just and reasonable standard of review to remain outside the Midwest ISO Energy Markets. It is just and reasonable to accept the Midwest ISO's proposed treatment of GFAs for those GFAs that did not settle and that are subject to a just and reasonable standard of review.[104] Including transactions under these contracts (50 GFAs, representing 4,992.7 MW) in the Energy Markets will better enable the Midwest ISO to operate those markets reliably and will not contravene the contractual rights of the parties to the GFAs.

138. The proposed TEMT does not rewrite the GFAs, although it does impose changes to the manner in which transmission service is provided for transactions under the GFAs. Thus, for example, Option A requires the GFA Responsible Entity to nominate and hold FTRs in order to transact under GFAs, and Option C requires the GFA Responsible Entity to pay the costs of congestion for all GFA transactions. As such, it is possible that replacing the current OATT with the TEMT, including its proposed treatment of GFAs, may affect the bargain between parties to individual GFAs. To the extent that costs are shifted between parties to GFAs in this category, the terms and conditions of GFAs subject to a just and reasonable standard of review allow the parties to propose

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[104] We determined that 50 of the non-settling GFAs are subject to a just and reasonable standard of review. Of those, parties to 31 of these GFAs explicitly agreed that their contracts are subject to a just and reasonable standard of review. For the remaining 19 GFAs, the presiding judges made a finding that the contracts are subject to a just and reasonable standard of review, and we affirm those findings.

appropriate modifications to reflect such new costs.[105] We find that this flexibility will adequately protect the parties to this category of GFAs from trapped costs.

139. Accordingly, we will require the Transmission Owners and ITC Participants providing service under these GFAs, either unilaterally or through agreement with their counterparties, to choose between the scheduling and settlement provisions of Option A or Option C (which we find are just and reasonable, as described below), and to notify the Midwest ISO of their selection, in accordance with the TEMT, before the commencement of FTR nominations.[106]

140. We disagree with the Midwest ISO TOs that our action here is precluded by the Midwest ISO Agreement. The Midwest ISO Agreement, by its express terms, does not abrogate GFAs or allow the Midwest ISO to modify the terms. However, it does not prevent the Commission or GFA parties from seeking modification to the GFAs pursuant to the GFAs' own terms. Our action in this docket makes the latter type of modification, and therefore is not barred by the Midwest ISO Agreement.[107]

(b) GFAs Where the Parties Have Explicitly Provided that the *Mobile-Sierra* Public Interest Standard of Review Applies

141. After the settled GFAs, plus the non-settled GFAs where the parties have explicitly provided that the just and reasonable standard of review applies, have been integrated into the markets, relatively few GFAs remain: 127 GFAs, representing 10,385.2 MW. Of these, 77 GFAs, comprising 6.914.4 MW, the parties have explicitly

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[105] As described above, the Commission expects that the increases in efficiency and competitiveness that accompany the implementation of the Energy Markets will offset these increased costs.

[106] *See* Module C, Section 38.8.3, Original Sheet No. 445.

[107] *See* Louisville Gas & Electric Company and Kentucky Utilities Company, 101 FERC ¶ 61,182 (2002), *reh'g denied* 103 FERC ¶ 61,104 (2003) (finding that Opinion 453-A was not intended to deny transmission owners the opportunity to recover from GFA customers the charges that Midwest ISO levies on transmission owners for service provided under GFAs, or require negotiation prior to the transmission owners' petitioning the Commission for change to the rates, terms or conditions of GFAs, where the GFAs themselves do not require such negotiation).

provided that they are subject to a *Mobile-Sierra* public interest standard of review.[108]

142. The Midwest ISO has requested that we modify all GFAs, including those subject to review under the *Mobile-Sierra* public interest standard, to ensure that it can reliably operate its Energy Markets. However, as described in the previous section, the record before us suggests that the Energy Markets, which are scheduled to start up on March 1, 2005, can be operated reliably, with net benefits to the public, notwithstanding a carve-out of these 77 GFAs until the transition period ends in 2008. We therefore cannot find today that the public interest requires that these GFAs be modified in order for the Energy Markets to operate reliably.

143. Thus, we will direct the Midwest ISO to carve these GFAs out of the Energy Markets for the remainder of the six-year transition period. A carve-out for this category of contracts, we reiterate, is possible only because of the small number of megawatts involved; larger carve-outs, in contrast, would require us to reevaluate this treatment (which, in any event, will terminate in 2008).[109]

144. Although these GFAs will not be subject to the TEMT's scheduling requirements, the Midwest ISO TOs stated in their comments that they are willing to provide non-binding day-ahead schedule information for GFAs to the Midwest ISO.[110] We accept the Midwest ISO TOs' offer. We direct them, to the extent that they take service under the Midwest ISO Tariff to meet their obligations under the GFAs in this category, to submit day-ahead and modified real-time schedules to the Midwest ISO in accordance with the timelines set forth in the TEMT.[111] This additional information will allow the Midwest ISO to better accommodate the GFAs that we are temporarily exempting from the responsibilities of the TEMT through the end of the transition period, and further

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[108] Twenty additional GFAs are silent as to the standard of review, and remain disputed; the transmission providers for 30 remaining GFAs are not jurisdictional public utilities.

[109] Formation Order at 62,167-70; Ameren Services Co., *et al.*, 103 FERC ¶ 61,178 at P 72 (2003).

[110] *See* Midwest ISO TOs' June Comments at 16, 20 and Attachment A at 4. Hoosier and Southern Illinois, which are not public utilities under section 201 of the FPA, have joined the Midwest ISO TOs' comments.

[111] *See* Midwest ISO TEMT §§39.1.1 and 40.1.1.

minimize the impact of the carve-out on the Day 2 markets. We expect these schedules to be as accurate as possible and will direct the Midwest ISO to file, on an informational basis, quarterly reports on the accuracy of the day-ahead schedules submitted for these GFAs within 30 days after the end of each calendar quarter.

145. We direct the Midwest ISO to file, within 60 days of the date of this order, a detailed explanation of how it will administer the carve-out. The Midwest ISO should include the following parameters in designing the carve-out: (1) the maximum MW capacity designated in this proceeding for each carved-out GFA should be removed from the model used for FTR allocation; (2) schedules submitted by the GFA parties in accordance with the TEMT day-ahead timelines should not be subject to congestion charges; (3) the Midwest ISO should incorporate the GFA parties' schedules into the Reliability Assessment Commitment procedures; and (4) the Midwest ISO should allow parties to carved-out GFAs to settle real-time imbalances through the provisions of their GFAs instead of requiring that such imbalances be procured through the Midwest ISO Real-Time Energy Market during the transition period.

146. OMS raises concerns about the unequal treatment of GFA transactions and non-GFA transactions in the new Energy Markets. It concedes that whether the discrimination is undue depends upon the impact that the carve-out will have, but highlights as unduly discriminatory the substitution of loss provisions in GFA contracts for those in the TEMT. Requiring parties to GFAs that are subject to a just and reasonable standard of review to abide by the scheduling and settlement rules that the Midwest ISO proposed for GFAs will help level the playing field and more appropriately distribute the costs of the Day 2 markets. The capacity under remaining GFAs – 10,385.2 MW, or 9.6 percent of the Midwest ISO's peak capacity – is sufficiently small that it will not harm the Midwest ISO's ability to provide service reliably. With respect to losses, OMS's concerns are premature. The TEMT II Order required the Midwest ISO to credit marginal losses back to a historical loss charge or average losses for all existing transmission customers for a five-year transition period and for all new transmission customers for a one-year transmission period.[112] In addition, the Commission required the Midwest ISO to pursue with stakeholders methods for ensuring that they are not significantly exposed to marginal loss charges without an opportunity to hedge against such charges; one such method may be to modify the loss pool mechanism.[113] The Commission directed the Midwest ISO to file revised proposals with the Commission to implement this transitional loss calculation measure and propose a long-term solution to

[112] *See* TEMT II Order at P 73-78.

[113] *See id*. at P 239.

address concerns about the lack of hedging mechanisms for marginal losses. If OMS's concerns about undue discrimination persist, it may raise those at the time those proposals are filed.

(c) <u>GFAs With No Specified Standard of Review</u>

147. Our review of the presiding judges Findings of Fact indicate that there are 16 additional GFAs, representing approximately 1,240 MW, for which the parties did not agree on what standard of review applies and that the presiding judges' found are silent on the standard of review. The presiding judges determined that the public interest standard applies to these GFAs.

148. Xcel argues on exceptions that the presiding judges erred in finding that four of its disputed GFAs do not permit unilateral rate modifications and are subject to the *Mobile-Sierra* public interest standard of review.[114] It alleges that those contracts are in fact silent as to the applicable standard of review.[115]

149. We will require the Midwest ISO to carve out these 20 "silent" contracts until the transition period ends in 2008[116] because the record before us suggests that the Energy Markets, which are scheduled to start up on March 1, 2005, can be operated reliably, with net benefits to the public, notwithstanding the carve-out of these 20 GFAs. We also require that the Transmission Owners and ITC Participants taking transmission service under the Midwest ISO Tariff to meet their obligations under these contracts submit day-ahead and modified real-time schedules to the Midwest ISO so that the Midwest ISO can handle transactions under these GFAs in the most efficient way possible. The Midwest ISO is directed to include day-ahead schedules for these contracts in its quarterly reports on schedules for carved-out GFAs.

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[114] *See* Findings of Fact at P 119.

[115] Xcel Brief on Exceptions at 17-18.

[116] The four contracts (totaling 32.4 MW) Xcel disputes will be included in the carve-out whether they are silent as to standard of review, as Xcel alleges, or whether they are subject to the *Mobile-Sierra* public interest standard, as the presiding judges found. Therefore, as further described *infra* in Section II (C)(5)(c), we do not need to make a finding as to the standard of review for these contracts.

(d) <u>Non-Jurisdictional GFAs</u>

150. Finally, we will require the Midwest ISO to carve out of the Energy Markets the 30 GFAs, representing 2,198 MW, for which the transmission provider is not a public utility as defined in section 201 of the FPA. The Commission has no authority to make any modifications to these contracts. However, the Commission does have jurisdiction over the service that the Transmission Owners must take under the Midwest ISO Tariff to meet their obligations under their GFAs. In addition, we note that Hoosier and Southern Illinois have joined the Midwest ISO TOs' comments, which state that the Midwest ISO TOs can submit correct, day-ahead schedules to the Midwest ISO. We accept this offer, and will require that Transmission Owners taking transmission service under the Midwest ISO Tariff to meet their obligations under GFAs in this category submit day-ahead and modified real-time schedules to the Midwest ISO so that the Midwest ISO can handle transactions under these GFAs in the most efficient way possible.[117] To the extent that the Midwest ISO receives (or does not receive) day-ahead schedules for these contracts, it is directed to include them in its quarterly reports on schedules for carved-out GFAs or to specify that it did not receive them.

5. <u>Discussion Regarding the Briefs on Exceptions to the Presiding Judges' Findings of Fact</u>

(a) <u>GFA Responsible Entity</u>

151. The presiding judges' in their Findings of Fact stated that, for nearly all of the GFAs set for hearing, the designation of the GFA Responsible Entity was disputed.[118] They asserted that finding the GFA Responsible Entity for each of the contracts, as defined in the TEMT,[119] required them to consider the Commission's prior precedent

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[117] We note that Southern Illinois and Hoosier are the only two non-jurisdictional Transmission Owners subject to the carve out, since other non-jurisdictional Transmission Owners (e.g., City of Columbia, Springfield City Water and Light) either do not have GFAs or have settled on one of the options proposed in the Midwest ISO TEMT.

[118] Findings of Fact at P 34.

[119] The TEMT describes the GFA Responsible Entity, Module C, § 38.8.1, Original Sheet No. 443, as follows:

a). The GFA Responsible Entity must be a fully qualified Market

(continued)

regarding RTOs and ISOs and that these principles were applicable to the issues set for hearing.[120] They explained that, in recent cases involving assignment or "pass-through" of RTO and ISO costs and charges, the Commission's policy has consistently been that it is appropriate to assign RTO and ISO costs to all customers using the grid, because all customers benefit from independent operation of the grid.

152. Under these precedents, the presiding judges stated that the transmission customer or the load-serving entity would be responsible for the charges that the GFA Responsible Entity would be obligated to pay under the TEMT. For the GFAs at issue in this proceeding, they found that these principles, standing alone, would require that the GFA Responsible Entity be the customer taking service over Midwest ISO facilities, because that customer is utilizing the grid and benefiting from its operation.[121] However, the presiding judges stated that the TEMT definition of GFA Responsible Entity in many cases prevents this finding, because it requires that the GFA Responsible Entity be a fully qualified Market Participant.[122] Accordingly, where the customer taking service under

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Participant under this Tariff.

b). The GFA Responsible Entity shall be financially responsible pursuant to the applicable GFA for:

(1) All Market Activities charges, as well as all charges under Schedules 16 and 17;

(2) All Transmission Usage Charges caused by the applicable Bilateral Transaction Schedules; and

(3) Any debits or credits associated with FTRs held by the GFA Responsible Entity.

[120] Findings of Fact at P 36 (*citing, inter alia,* Midwest Independent Transmission System Operator, Inc., 98 FERC ¶ 61,141 (2002); Pacific Gas & Electric Company, *et al*., 101 FERC ¶ 61,151 (2002); California Independent Transmission System Operator, 103 FERC ¶ 61,114 (2003) (Opinion No. 463), *order on reh'g*, 106 FERC ¶ 61,032 (2004) (Opinion No. 463-A)).

[121] Findings of Fact at P 38.

[122] Under § 1.184 of the TEMT, Market Participant is defined as:

(continued)

the GFA was not a fully qualified Market Participant under the TEMT, the presiding judges found that the counter-party was the GFA Responsible Entity by default.

(1) Parties' Exceptions

153. A number of parties filed exceptions to the presiding judges' determination as to which party to the GFA should be the GFA Responsible Entity. GFA customers under the GFAs generally argue that the presiding judges misapplied Commission precedent. They argue that the precedent relied upon involves the pass-through to GFA customers of costs incurred by transmission owners taking service from an RTO to serve their GFA obligations. In fact, they state, Opinion Nos. 453 and 453-A actually stand for the opposite proposition because, in that proceeding, the Commission specifically rejected requests to allow the Midwest ISO to charge its Schedule 10 adder directly to GFA customers.[123]

154. With regard to the presiding judges' reliance on Opinion Nos. 463 and 463-A, in which the Commission approved Pacific Gas and Electric Company's (PG&E) proposal to pass through to GFA customers the costs that PG&E incurs with respect to the CAISO grid management services, commenters note that the Commission did not address in those orders whether the CAISO could charge GFA customers directly for those costs, as it had already been resolved that the transmission owners, and not the customers, would be assessed the costs in the first instance. They note that the Commission based its approval of PG&E's proposal on the finding that CAISO's grid management services, which include performing operation studies, system security analysis, emergency management, outage coordination, and transmission planning, were new services not provided for in existing contracts, that benefit GFA customers. In doing so, the Commission distinguished CAISO's grid management services from the reliability service (*i.e.*, redispatch) costs that the Commission previously had not allowed to be

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> 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.

[123] *See* Basin, *et al*. brief at 15-18, EKPC brief at 9-10, Rural Electric Cooperatives brief at 9-11.

passed through to GFA customers as a new service in Opinion Nos. 459 and 459-A.[124] In Opinion Nos. 459 and 459-A, the Commission refused to find that reliability services are new services, stating that customers taking service under GFAs presumably already receive such service as part of the firm service provided to them in their contracts.[125]

155. GFA customers argue that there is a clear distinction between the grid management services for which the Commission allowed pass-through of costs as a new service in Opinion Nos. 463 and 463-A and the charges that must be born by GFA Responsible Entities under the TEMT. They argue that Commission precedent requires that the Commission determine whether the Midwest ISO services at issue in this proceeding are already being provided under the GFAs and, if they are, that the costs should be assigned to the Transmission Owners in the first instance. Customers argue that the costs of congestion for which the GFA Responsible Entity would be responsible under the TEMT are associated with redispatch service that, according to Opinion Nos. 459 and 459-A, is presumed to be a part of firm transmission service already provided in the GFAs. Therefore, the GFA customers should not be the Responsible Entities because the transmission-owning parties to the GFAs are already obligated to provide the service which the TEMT requires GFA Responsible Entities to take and charging GFA customers directly for such service would result in impermissible double charges for these services.[126]

156. Rural Electric Cooperatives argue that a GFA customer takes service under the GFA and not the Midwest ISO's tariff. Furthermore, they argue that Opinion No. 453-A establishes the precedent that parties must negotiate an amendment to the GFA in order for a Transmission Owner to collect any additional charges.

157. Minnesota Power, Cleveland and AMP-Ohio argue that the presiding judges reached a formulistic result for each contract based on the TEMT and generic principles of Commission precedent and in so doing erred in determining the GFA Responsible Entity and GFA Scheduling Entity and inappropriately modified the contracts. They argue that the presiding judges should have reviewed each contract and, based on the

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[124] Pacific Gas & Electric Company, Opinion No. 459, 100 FERC ¶ 61,160 at P 19-20, *reh'g denied*, Opinion 459-A, 101 FERC 61,139 (2002).

[125] *Id*. at P 19-22.

[126] *Id*. at P 22-26

assignment of rights and responsibilities under the contract, determined the appropriate GFA Responsible Entity and GFA Scheduling Entity.

158. EKPC argues that the only party to its GFAs that is a member of the Midwest ISO is LG&E and that shifting costs to EKPC for a decision made by LG&E is not consistent with the Commission's policy to preserve the commercial bargain between the parties to GFAs.[127] Only by designating LG&E as the GFA Responsible Entity can the GFAs be honored consistent with Commission policy. Northwestern, MMTG and others state that the presiding judges err in finding that transmission customers and load-serving entities will benefit from the Midwest ISO's Energy Markets.

159. Transmission Owners generally take exception to the presiding judges' finding that the GFA Responsible Entity should be the counter-party when the load serving entity is not a Market Participant under the TEMT. Rather than allowing the tariff definition to determine which entity should be the GFA Responsible Entity, the Commission should rely on its precedent to determine that the load serving entity should be responsible for the charges.[128] Allowing entities to shift costs to other Market Participants by delaying or failing to qualify for Market Participant status provides opportunities for gaming and is fundamentally unfair. Rather, they submit, the Commission should require Midwest ISO to amend the TEMT to require that a load serving entity must qualify as a Market Participant in order to receive grandfathered service to its load.[129] LG&E argues that as the entity making decisions that cause congestion, the load-serving entity should face the LMP price signal to encourage it to make efficient use of the grid. Otherwise, the load serving entity could harm other market participants by increasing the congestion costs of other transactions.[130]

(2) <u>Commission Discussion</u>

160. To the extent that parties to a GFA have agreed upon the designation of GFA Responsible Entity, we will adopt that designation to establish financial responsibility for GFAs that are subject to Options A, B or C, pursuant to settlements or the requirements of this order.

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[127] EKPC brief at 12 (*citing* Procedural Order at P 51).

[128] LG&E brief at 26.

[129] *Id*.

[130] *Id*. at 29-30.

161. To the extent that parties to the GFA have not agreed upon the designation of GFA Responsible Entity, we find that the GFA Responsible Entity should be the Transmission Owner or ITC Participant responsible for providing transmission service under the GFA. This is consistent with Opinion Nos. 453 and 453-A and section II.A.2.a of Appendix C of the Midwest ISO Agreement, which require that a Transmission Owner or ITC Participant take transmission service under the Midwest ISO Tariff in order to satisfy its obligations under a GFA, and section II.A.3.f of Appendix C of the Midwest ISO Agreement, which provides that service under GFAs will continue pursuant to the terms of a GFA. With respect to Rural Electric Cooperatives' argument that Opinion No. 453-A establishes the precedent that parties must negotiate an amendment to the GFA in order for a Transmission Owner to collect any additional charges, as we clarified in *Louisville Gas & Electric Company and Kentucky Utilities Company*,[131] Opinion No. 453-A was not intended to deny Transmission Owners the opportunity to recover from GFA customers the charges that Midwest ISO levies on Transmission Owners for service provided under GFAs or to require negotiation prior to the Transmission Owners' petitioning the Commission for change to the rates, terms or conditions of GFAs where the GFAs does not require such negotiation.

162. Our decision here is also consistent with more recent precedent cited by the presiding judges concerning the pass through of costs incurred under regional transmission provider tariffs to meet obligations under GFAs. While in Opinion Nos. 463 and 463-A the Commission found that grid management services performed by a regional transmission provider constitute new services presumed to not be provided for in GFAs (unless the GFAs expressly contemplate responsibility for the cost of such services), the costs at issue for GFAs choosing Options A, B, or C or converting to TEMT service are more extensive than grid management services performed by a regional transmission provider. Transmission usage charges, FTR debits and credits, and uplift costs are essentially redispatch costs, substantially similar to the redispatch costs associated with the reliability services at issue in Opinion Nos. 459 and 459-A. There, the Commission rejected PG&E's proposal to pass through to customers under existing firm transmission service contracts, as a new service, the reliability service costs that it incurs under the CAISO tariff to meet its obligations under the existing contracts. Rather, the Commission found that redispatch service must be presumed to be included in the firm transmission service provided in the contracts and thus does not constitute a new service.[132] Similarly, here we do not allow such costs to be charged directly to the

[131] 101 FERC ¶ 61,182 (2002), *reh'g denied*, 103 FERC ¶ 61,104 (2003).

[132] *See* Opinion No. 459 at P 19-20.

customers under the GFAs, unless the GFA parties have specifically agreed otherwise in their joint filings. Instead, we require the transmission owner or ITC participant to bear the costs. We agree with LG&E that efficient use of the grid would be promoted if those with decision-making responsibility for transactions under GFAs were also financially responsible for congestion costs. However, that is a matter more appropriately addressed when parties seek to modify their GFAs to reflect treatment of those GFAs under the TEMT.

(b) GFA Scheduling Entity

163. With respect to determining the GFA Scheduling Entity where the GFA parties did not agree upon that designation, the presiding judges found that the TEMT's definition[133] makes clear that the GFA Scheduling Entity must be either the GFA Responsible Entity or an agent designated by the GFA Responsible Entity.[134] Accordingly, the presiding judges found that the GFA Responsible Entity has also been deemed the GFA Scheduling Entity.

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[133] The TEMT defines GFA Scheduling Entity as follows:

> a. All entities operating pursuant to Grandfathered Agreements shall designate a GFA Scheduling Entity within the time set forth in Section 38.2.5.k. The GFA Scheduling Entity shall submit Bilateral Transaction Schedules consistent with the provisions set forth herein for any sales and/or purchases of Energy pursuant to the Grandfathered Agreement.
>
> b. The GFA Scheduling Entity responsible for submitting such Bilateral Transaction Schedules shall either be the GFA Responsible Entity or a Scheduling Agent designated by the GFA Responsible Entity.

Module C, section 38.8.2, Original Sheet No. 444.

[134] Findings of Fact at P 40.

(1) Parties' Exceptions

164. Parties[135] state that the presiding judges erred in concluding that the GFA Scheduling Entity must also be either the GFA Responsible Entity or the GFA Responsible Entity's designated agent. Parties maintain that the presiding judges' decision is inconsistent with the contractual provisions for scheduling generation to load under the GFA and could create a reliability problem for the GFAs.

(2) Commission Discussion

165. Where the GFA Responsible Entity is financially responsible for the market impact costs of GFA transactions, then the GFA Responsible Entity must have the final say on the schedule that it submits into the Day-Ahead Energy Market for that transaction. To do otherwise would undermine the GFA Responsible Entity's ability to limit its costs for transactions under the GFA. For example, where a Transmission Owner is designated as the GFA Responsible Entity, the Transmission Owner should have discretion to use FTRs allocated to it through Option A treatment to limit the costs of the GFA transactions. To do this, unless it has agreed otherwise, the Transmission Owner must be able to schedule its best estimate of the GFA transactions in the Day-Ahead Energy Market and thus must be the GFA Scheduling Entity as that term is defined in the TEMT unless it agrees otherwise.

166. We note that designation of a particular GFA party as the GFA Scheduling Entity does not modify the rights and obligations for scheduling between the parties as currently contained in the GFA. Rather, the GFA Scheduling Entity is the entity that interacts with the Midwest ISO and the Midwest ISO Day 2 markets to schedule GFA transactions. If there are obligations in the GFA, where parties to the GFA provide one another with load and scheduling information, we expect continued full exchange of this type of information, whether the GFA is carved out or subject to the provisions of the TEMT. Consistent with this expectation of continued flow of schedule information between parties to the GFA, we direct all Transmission Owners and ITC Participants to update the Midwest ISO periodically as they receive changed information on the schedule for their carved-out GFA transactions. Under these directives for carved-out GFAs, the Midwest ISO will receive schedules from the Transmission Owners and ITC Participants on a day-ahead basis, as updates are provided to the Transmission Owners and ITC Participants by

[135] Basin, *et al*., Cleveland and AMP-Ohio, EKPC, FirstEnergy, Great River, LG&E, Minnesota Power, Minnkota, Northwestern, Xcel, WPS Resources, and Alliant.

GFA parties or loads under the GFAs, and as a final update 30 minutes prior to the operating hour.

(c) Standard of Review

(1) Parties' Exceptions

167. Otter Tail, Xcel and Northwestern argue that Commission precedent requires a party to specifically state that the public interest standard applies to contract modifications and if the contract is silent as to the standard of review for contract modifications, that the just and reasonable standard applies since neither party waived its unilateral filing rights.

168. Great River, Basin, *et al.*, Minnkota, Dairyland, the Rural Electric Cooperatives, Cleveland and AMP-Ohio argue that the Findings of Fact mistakenly found the Commission could modify silent contracts under the just and reasonable standard of review. They argue that the presiding judges, in basing their findings on *Union Pacific Fuels, Inc. v. FERC,*[136] ignored subsequent appellate history that modified that ruling and held that the *Mobile-Sierra* standard would apply in such situations.[137]

(2) Commission Discussion

169. As our decision here only affects GFAs that are subject to a just and reasonable standard of review and does not affect the terms and conditions of GFAs that are either silent with respect to the standard of review or those GFAs where the parties have explicitly provided that the *Mobile-Sierra* public interest standard of review applies, we do not need to reach a decision on this issue here.

(d) The Presiding Judges' Database

(1) Parties' Exceptions

170. Basin, *et al.*, Dairyland and the Rural Electric Cooperatives argue that the Findings of Fact rely on a secret, limited, summary database created for this proceeding and that since, this database is not accessible by the parties, they are unable to review or effectively challenge the information used to formulate the Findings of Fact. Basin, *et al*.

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[136] 129 F.3d 157 (D.C. Cir. 1997).

[137] *See* Texaco Inc v. FERC, 148 F.3d 1091 (D.C. Cir. 1998).

state that basic administrative law principles require that the database be made publicly available and that the parties be granted sufficient time to evaluate the information before the Commission makes any decision.

171. Basin, *et al.* further argue that the data summaries contained in Attachment A and B to the Findings of Fact represent an attempt to force complex contractual agreements into a simple template, and, consequently, these summaries are incomplete and inaccurate characterizations of the terms and conditions of the contracts. Therefore, Basin, *et al*. argue that the Commission cannot rely upon only these summary sheets when making decisions about individual GFAs, or GFAs as a group.

(2) Commission Discussion

172. The presiding judges stated that the information in the database is available for use by the Commission's Office of Markets, Tariffs and Rates and explain that a public version of these records was attached to the Findings of Fact.[138] This implied that the database contains additional information or calculations not disclosed in the public version. However, Attachments A and B to the Findings of Fact reflect all of the information that the presiding judges provided to the Commission. The Commission and staff considered the text, Attachment A and Attachment B of the Findings of Fact, but also conducted their own contract-by-contract analysis using the full record for each GFA in this proceeding. The database does not contain, and so the Commission did not consider, any information not disclosed in the Findings of Fact or included in the record. Therefore, any concerns regarding consideration of non-public information in the database are unwarranted.

(e) Due Process

(1) Parties' Exceptions

173. LG&E argues that the trial schedule in this case deprived the parties of due process. Citing the Commission's Web site, LG&E argues that the Commission's standards for a simple case allow for 19.5 weeks from the date of the order designating a presiding judge to the date of the hearing, but that the Commission allowed only four weeks. During these four weeks, the parties were required to conduct settlement negotiations and prepare requests for rehearing of the Procedural Order. Additionally, since the GFA testimony was to be filed on Friday, June 25, 2004, for a hearing to be held starting Monday, June 28, 2004, LG&E states that it did not have adequate time to

[138] Findings of Fact at P 32.

conduct meaningful discovery or trial preparation as to the issues raised in the filed testimony. Therefore, there was insufficient time to develop an adequate record of the case. LG&E adds that the hearing was based on a conditionally-approved TEMT, which could still change. LG&E argues that the Commission did not provide any justification for the trial schedule, except that the Commission and the Midwest ISO are in a rush to allocate FTRs in October.

(2) Commission Discussion

174. We are not persuaded that the hearing schedule in this case harmed LG&E or any other hearing participant. Although LG&E claims that there was insufficient time to develop an adequate hearing record, it does not explain what aspects of the hearing record are inadequate, or specifically how the hearing schedule harmed LG&E.

175. We reject LG&E's argument that the Commission should have allowed at least 19.5 weeks between the date the Presiding Judges were designated and the beginning of the hearing. The portion of the Commission's Web site that LG&E cites notes that the time standards for hearings "were designed to process cases as quickly as possible, consistent with due process and the Commission's requirement for a full and complete record."[139] Shorter or longer periods for discovery are permissible, as the case requires.[140] And while the standard length of time for a simple case is 19.5 weeks, nothing limits the Commission's authority to set whatever length of time it deems appropriate.[141]

176. Further, the Commission provided numerous procedural safeguards to streamline and simplify the process of discovering GFA information. The Procedural Order specified that the hearing should be narrowly focused in order to facilitate discovery of

[139] Processing Time Standards for Hearing Cases, http://www.ferc.gov/legal/admin-lit/time.asp.

[140] *See id.*

[141] The notice or order establishing hearing is required to describe: (a) the authority and jurisdiction under which the hearing will be held; (b) the nature of the proceeding; (c) certain procedural dates; (d) the name of the presiding officer, if known; and (e) any other appropriate matter. *See* 18 C.F.R. § 385.502(b) (2004). The Commission's Web site acknowledges that the Commission may change the standard timeline. *See* Summary of Procedural Time Standards for Hearing Cases, http://www.ferc.gov/legal/admin-lit/time-sum.asp ("These times standards [*sic*] apply unless the Commission order directs otherwise.").

well-defined GFA information that the Commission needed to complete the record for the instant order.[142] The Procedural Order allowed parties to avoid the Step 2 hearing entirely by agreeing to their GFA information and filing it, jointly, with the Commission before the hearing began.[143] It also allowed parties to agree on their GFA information during – or even after – the hearing, to withdraw from the proceeding and to submit their own resolution of any disputes regarding GFA information.[144] These safeguards allowed the parties a continued opportunity to determine the information in a cooperative, rather than an adversarial, setting.

(f) Standard of Conduct

(1) Party Exception

177. LG&E argues that the presiding judges erred in finding that the testimony of and LG&E witness, Charles Freibert, Jr., violated the independent functioning requirement in the Commission's Standards of Conduct.[145] LG&E asserts that since its witness was testifying to public, non-transaction-specific information in a public forum, his testimony should not have been precluded based on the independent functioning requirement. Furthermore, LG&E states that Charles Freibert, Jr. is the Director of Energy Marketing at LG&E and does not conduct transmission system operations; therefore, he is not a transmission function employee.

(2) Commission Discussion

178. The Standards of Conduct govern the relationship between transmission providers and their affiliates to prevent transmission providers and their affiliates from using non-public transmission information to compete unfairly with non-affiliates.[146] Among the mechanisms used to prevent unduly discriminatory treatment are requirements that transmission function employees function independently from the affiliate and not share

[142] *See* Procedural Order at P 68, 76.

[143] *See id*. at P 69-70.

[144] *See id.* at 77.

[145] *See* Standards of Conduct for Transmission Providers, Order No. 2004, 68 Fed. Reg. 69,134 (2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), *order on reh'g*, Order No. 2004-A, 69 Fed. Reg. 23,562 (2004), *order on reh'g*, Order No. 2004-B, 69 Fed. Reg. 48,371 (2004).

[146] Order No. 2004 at P 15.

or provide access to non-public information.[147] A principal purpose is to prevent the sharing of non-public information with an affiliate that would give that affiliate an advantage over a non-affiliate. However, Order No. 2004 allows transmission providers and their affiliates to share with their marketing and energy affilliate, among other personnel, senior officers and directors who do not engage in day-to-day transmission functions.[148] If Mr. Freibert's testimony was limited to public, non-transaction specific information, then his knowledge and his testimony did not violate the independent functioning or the information access provisions of the Standards of Conduct. However, based on the record before us, it is unclear whether the testimony reflected only such public information or not. On the other hand, the presiding judges found, and we agree, that most of the testimony stricken from the record was outside the scope of the six questions, and the remaining information is not necessary to the Commission's decision.[149]

(g) <u>GFA Nos. 205, 206, 207, 267, 268, and 269</u>

179. GFA Nos. 205, 206, 207, 267, 268, and 269 (Ludington GFAs) represent four agreements that pertain to the Ludington Hydroelectric Pumped Storage Plant (Ludington Plant). The Ludington Plant, with a total generating capability of 1,872 MW,[150] is owned and operated jointly by Consumers and Detroit Edison.[151] GFA Nos. 205 and 269 are the same contract and contain both the Ownership and the Operating Agreement for the Ludington Plant. GFA Nos. 206 and 267 are the same contract, the Project Transmission Facilities Agreement for the Ludington Plant. The Project Transmission Facilities Agreement provides for service over the transmission facilities of Michigan Electric Transmission Company, LLC (METC) and International Transmission Company (ITC) associated with Consumers' and Detroit Edison's interest in the Ludington Plant.[152] GFA

[147] 18 C.F.R. § 358.4(a)(1) (2004) (independent functioning requirement); 18 C.F.R. § 358.5(a) - (b) (2004) (information access and disclosure prohibitions).

[148] Order No. 2004 at P 102-04; 18 C.F.R. § 358.4(a)(5) (2004).

[149] Findings of Fact at P 50-52.

[150] Exh. DE-1, Byron testimony at 4; Exh. CEC-1, Gaarde testimony at 4.

[151] Findings of Fact at P 319.

[152] *Id*.

Nos. 207 and 268 are the same contract, the Transmission Facilities Agreement. GFA Nos. 207 and 268 deal with construction, operation, maintenance and use of certain transmission facilities related to the construction of the Ludington Plant that are no longer owned by either Consumers or Detroit Edison.[153] Parties to the Ludington GFAs agreed as to the source and sink points for the GFAs, that the cumulative maximum number of megawatts transmitted under the GFAs is 2,040 MW, and that the Ludington GFAs are explicitly subject to a *Mobile-Sierra* public interest standard of review.[154] There was no agreement as to the GFA Responsible Entity and the GFA Scheduling Entity for these agreements and thus these issues were set for hearing.

180. The presiding judges found that the Ludington GFAs are unique since they are the only GFAs that relate to a pumped storage facility in the Midwest ISO's footprint.[155] The judges also state that the Ludington Plant is transmission dependent because it requires transmission service both to deliver the output of the plant to Consumers' and Detroit Edison's load, and to deliver electricity to fuel the plant by pumping water back into the reservoir.[156] The presiding judges found that Detroit Edison and Consumers benefit from the Midwest ISO services and should both be designated as GFA Responsible Entities for the Ludington GFAs. Consistent with this finding, the presiding judges designated both Detroit Edison and Consumers as the GFA Scheduling Entities for the Ludington GFAs. Finally, the presiding judges noted that throughout the hearing process the parties have been in discussions with the Midwest ISO regarding the possibilities of altering the TEMT to accommodate the unique circumstances posed by the Ludington GFAs.[157]

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[153] Exh. CEC-1 at 7.

[154] June 25, 2004 Supplemental Joint Written Statement of Detroit Edison, Consumers, METC, and ITC at 4-5.

[155] The plant is located on the western edge of Consumers' service territory. Findings of Fact at P 324.

[156] *Id*. at 325.

[157] *Id*. at n. 124.

(1) Party Exceptions

181. Detroit Edison argues that the Findings of Fact fail to find that the unique attributes of the Ludington Plant require accommodation during implementation of the Midwest ISO TEMT. Detroit Edison states that the Ludington Plant is unique because, unlike other generating facilities, it can be dispatched very quickly, can provide load following or regulation, and 10 minute operative reserves to respond to real time contingencies, requires transmission to deliver power to the facility and transport power away from the facility, and utilizes energy limited resources. Detroit Edison states that since "the facility is dispatched on a day-of or real time basis" there is no way to provide day-ahead schedules for the output of the unit that would prevent the Ludington GFA parties from paying real-time congestion costs under the provisions of the Midwest ISO TEMT.[158] Detroit Edison is concerned that this inability to provide accurate day-ahead schedules could result in significant real time congestion costs under the proposed provisions of the TEMT. Detroit Edison argues that in failing to account for the uniqueness of the Ludington Plant, TEMT's provisions do not accommodate the operating rights and responsibilities established in the Ludington GFAs.

182. Detroit Edison also argues that the presiding judges erred in suggesting that Detroit Edison should be the GFA Responsible Entity for transmission over the METC transmission system. Because the Ludington Plant is located on the western edge of Consumers' service territory, Detroit Edison requires transmission service over both the ITC and METC transmission systems in order to transport energy to the Ludington Plant for pumping and from the Ludington Plant for delivery of power to Detroit Edison's load. Detroit Edison asserts that the Commission should designate Detroit Edison as the GFA Responsible Entity for GFA transactions in the METC system and Consumers as the GFA Responsible Entity for GFA transactions using the ITC system.

183. The Midwest ISO, in its August 17, 2004 informational filing, advised the Commission of its analysis of the megawatt quantities represented by each GFA. For the Ludington GFAs, the Midwest ISO estimated the total megawatt capacity at 2,040 MW.

(2) Commission Discussion

184. In the TEMT II Order, we stated that we agreed with Detroit Edison that converting its Ludington GFA rights to FTRs presents a challenge.[159] At that time we

[158] Detroit Edison brief at 12.

[159] TEMT II Order at P 185.

stated that without sufficient detail on the current rights associated with the Ludington Plant, we could not determine whether it was reasonable to grant the Ludington GFA parties rights beyond those granted non-GFA parties in the TEMT. The instant proceeding has provided the information necessary to determine the treatment of the Ludington GFAs.

185. Since the Ludington GFA parties agree that their contracts contain a Mobile Sierra standard of review, and since they have demonstrated that their rights and responsibilities under the Ludington GFA, as well as the operations of the Ludington Plant, are unique, we grant the parties the accommodation they seek. We direct the Midwest ISO to carve these GFAs out of the Energy Markets for the remainder of the six-year transition period. We require Detroit Edison and Consumers to submit day-ahead and modified real-time schedules, as well as any intervening updates, to the Midwest ISO for each utilities' GFA transactions providing pumping energy to the Ludington Plant and for GFA transactions where power flows from the Ludington Plant to Consumer's or Detroit Edison's loads.

186. We are concerned that Detroit Edison has stated that it cannot effectively provide day-ahead schedules for the Ludington Plant. We construe Detroit Edison's comment as support for why it should not be required to pay congestion costs in the Midwest ISO's Real-Time Energy Market for transactions under the Ludington GFAs rather than a statement that it is unwilling to provide its best estimate of GFA transactions a day before they occur. We note that the scheduling requirement directed above does not have financially binding impacts for differences from the day-ahead to real time schedules for GFA transactions. We believe this addresses Detroit Edison's concern about real-time congestion costs. However, given the scheduling challenges that Consumers and Detroit Edison identify for the Ludington Plant and the fact that the Ludington Plant has a large generating capability and its operation has significant reliability impacts on the grid, we will require additional coordination with the Midwest ISO. In this respect, we direct Consumers and Detroit Edison to share information with the Midwest ISO about restrictions on the Ludington Plant's use and any daily and hourly contingencies the units face.

187. We find that the Midwest ISO has overestimated the peak megawatt capacity associated with these GFAs. The joint filings show that when the plant is a load, pumping water back into the upper reservoir, 2,040 MW flows from Consumers and Detroit to the Ludington Plant.[160] However, historical data shows that the plant did not

[160] July 25 Supplemental Joint Written Statement Regarding GFA Nos. 205, 206, 207, 267, 268, 269 at 5. At times, usually during periods of low system demand, a pumped storage plant is a load, and draws power from other generators to pump water

(continued)

pump during peak periods of the last three years.[161] Since both Consumers and Detroit state that the generating capability of the plant is 1,872 MW, and historical data shows that the maximum output on peak has been significantly less that the generating capability,[162] we find that the Midwest ISO should carve out on-peak capacity from its FTR model equal to the generating capability of the plant for the Ludington GFAs prior to its initial FTR allocation. The Midwest ISO should carve out off-peak capacity for the Ludington GFAs equal to the pumping load, 2,040 MW.

(h) GFA Nos. 297 and 308

188. Central Power Electric Cooperative (CPEC) and East River Electric Cooperative (EREC) supply wholesale power to their member cooperatives from fixed allocations of hydropower from the Western Area Power Administration. GFA No. 297 is an integrated transmission agreement between CPEC and Otter Tail that allows each entity to provide transmission to the other entity over shared facilities. GFA No. 308 is an interconnection and transmission service agreement between EREC and Otter Tail under which Otter Tail provides transmission service to two of EREC's member cooperatives. The presiding judges found that, based on certain findings of fact, the TEMT should not apply to GFA Nos. 297 and 308 and that the two contracts should be removed from the proceeding. The presiding judges based this finding, on, among other things, the facts that: (1) CPEC, party to GFA No. 297, and EREC, party to GFA No. 308, are non-jurisdictional entities; (2) all of CPEC's and EREC's GFA loads are served from generators located in the WAPA control area; and (3) CPEC and EREC's loads served under these two GFAs are dynamically scheduled or short interval scheduled out of Otter Tail's control area. In the alternative, should the Commission decide that the TEMT should apply to these GFAs, the judges found that (1) the *Mobile-Sierra* public interest standard of review applies to both of these contracts; (2) the GFA Responsible Entity for GFA Nos. 297 and

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back into its upper reservoir. Because pumping is not perfectly efficient, there are performance losses associated with moving water to the upper reservoir. Thus it takes more power to move the water to the upper reservoir than is created when the plant is releasing water to generate power.

[161] July 9 Supplemental Joint Written Statement Regarding GFA Nos 205,206,207, 267, 268, 269, Attachment A.

[162] *Id*.

308 is Otter Tail; and (3) the GFA Scheduling Entity for both GFAs is WAPA acting as an agent for Otter Tail.

(1) <u>Parties' Exceptions</u>

189. Basin, *et al*. agrees with the Findings of Fact that GFA Nos. 297 and 308 should not be subject to the TEMT; however, it disagrees with the individual findings if the Commission decides to include the GFAs under the TEMT. Basin, *et al*. states that, as to GFA No. 297, Otter Tail should be the GFA Responsible Entity, WAPA should be the GFA Scheduling Entity, and 150 MW is the maximum under the contract; as to GFA No. 308, Otter Tail should be the GFA Responsible Entity, WAPA the GFA Scheduling Entity, and approximately 16 MW is the maximum amount transmitted under the contract. Basin, *et al*. also asserts that the TEMT should not apply to GFA No. 297 because Otter Tail did not transfer to the Midwest ISO the portion of Otter Tail's facilities that is required to serve the CPEC loads.

(2) <u>Commission Discussion</u>

190. We find that Otter Tail provides transmission under GFA No. 308, much like a through-and-out transaction. For this reason we find that GFA No. 308 cannot be removed from this proceeding. In the normal course of operation, since EREC's load is dynamically scheduled out of Otter Tail's control area, Otter Tail provides wheeling across its system (but does not provide ancillary services or imbalances under this contract). This does not mean that the flows over Otter Tail's transmission lines cannot in the future cause congestion that impacts the Midwest ISO's SCED in its Day-Ahead and Real-Time Energy Markets. We also find that GFA No. 308 is silent as to the standard of review as both parties agree that it contains no provisions for unilateral changes to the contract. For this reason, consistent with our finding on GFAs that are silent as to the standard of review, we direct the Midwest ISO to carve this contract out of the Energy Markets for the duration of the transition period. We affirm the presiding judges' alternative finding for the source and sink points and find that the maximum number of MW transmitted pursuant to the GFA is the highest number of the three years of historic data, 16.2 MW.

191. We note that EREC has pledged to give its load and scheduling information to the Midwest ISO.[163] We also note that Otter Tail does not serve load under GFA No. 308. For this reason we will direct EREC, rather than Otter Tail, to provide the day-ahead scheduling information transactions under this GFA, consistent with our discussion

[163] Findings of Fact at P 223.

above. Finally, we expect that EREC will register with the Midwest ISO as a market participant so that if it ever needs to purchase energy in the Midwest ISO market, for an emergency or otherwise, it will be subject to the TEMT for those transactions.

192. We also find that GFA No. 297 cannot be removed from this proceeding at this time. Since we do not have sufficient information to determine whether transmission service under GFA No. 297 is provided over Midwest ISO facilities, we set this GFA for hearing as described below. We also find that GFA No. 297 is silent as to the standard of review as both parties agree that it contains no provisions for unilateral changes to the contract. For the purposes of the interim period, as also described below, we direct that GFA No. 297 be carved out of the Energy Markets.

(i) GFA Nos. 273, 284, 297, 306, 309, 311, 313, 314, 316, 317, and 450

(1) Parties' Exceptions

193. Minnkota asserts that it does not transmit power over Midwest ISO facilities under GFA Nos. 284, 309, 311 (a duplicate of 273), 313, 314, 316, 317, and 450 because its rights to use the facilities identified in the GFAs were never transferred to the Midwest ISO. It states that it does not use the Midwest ISO controlled grid to serve its load under the GFAs. Therefore, Minnkota argues the neither the Midwest ISO nor the Commission nor any other party can lawfully impose TEMT costs on Minnkota.

194. Otter Tail argues that the Findings of Fact should have excluded GFA Nos. 297, 306, 309, 311, 313, 314, and 317 since these are integrated transmission agreements that govern the joint construction and operation of transmission facilities and the non-public utility parties' use of their own transmission rights. Furthermore, Otter Tail states that it transferred to the Midwest ISO only those rights it controlled, (*i.e.*, transmission rights to move its power to its load), not those rights it did not control (*i.e.*, transmission rights of the non-public utility counter-parties[164] to move power over the integrated transmission facilities to their loads). Therefore, since these entities will not be receiving Midwest ISO service, these agreements should have been excluded. Basin, *et al*. concurs with Otter Tail that the TEMT should not apply to GFA No. 297 because Otter Tail did not transfer to the Midwest ISO the portion of Otter Tail's facilities that is required to serve the CPEC loads.

[164] CPEC, GRE and Minnkota.

195. Minnesota Power argues that GFA Nos. 316 and 450 are not transmission agreements and were incorrectly included in this proceeding. Minnesota Power states that GFA Nos. 316 and 450 are interconnection agreements that do not provide for transmission service, but require the parties to take service under a separate agreement and that it takes transmission service under the Midwest ISO Tariff for the paths covered by these agreements. Minnesota Power argues that any interpretation of these agreements would result in a direct violation of Order No. 888.

(2) Commission Discussion

196. We do not have sufficient information in the record before us to determine whether transmission service under the above-listed GFAs is provided over Midwest ISO facilities or whether these contracts should be excluded from this proceeding and not be considered GFAs for purposes of the Energy Markets. It may be that some of these GFAs will impact the Energy Markets, while others will not. Importantly, input from the Midwest ISO on whether control of the facilities in question was transferred to the Midwest ISO (as Transmission Provider) is lacking. Therefore, we will set them for further hearing and settlement judge procedures. In this further proceeding, the parties can address the threshold issue of whether the service provided under these contracts will impact operation of the Energy Markets. In addition to this issue, parties should also address which facilities have been transferred to the control of the Midwest ISO and the six pieces of information the Commission asked for in Step 1, as described in the Procedural Order. This information is important in order to determine if these contracts should be excluded and, if not, how they should be treated under the TEMT. While the Midwest ISO has not commented specifically on these GFAs, its input is vital for us to determine the correct treatment of these contracts. Therefore, we expect the Midwest ISO to actively participate in this hearing.

197. However, while we are setting these matters for a further trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[165] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[166] The

[165] 18 C.F.R. § 385.603 (2004).

[166] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their (continued)

settlement judge shall report to the Chief Judge and the Commission within 60 days of the date of this order concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

198. Finally, we note that the Midwest ISO needs to know how to account for service under these GFAs during the interim period until these issues are finally resolved. We note that these GFAs are either silent as to the standard of review or the parties have explicitly agreed that they are subject to the *Mobile-Sierra* public interest standard of review. Therefore, consistent with our discussion above, we direct the Midwest ISO to carve each of these GFAs out of the Energy Markets.

(j) GFA Nos. 220 and 221

(1) Presiding Judges' Findings of Fact

199. Historically, EKPC has served its loads on the LG&E/Kentucky Utilities Company system from generation within its own control area. However, while there are delivery points outlined in the GFAs, these GFAs are silent on source points. The presiding judges found that the determination of whether the source points under these GFAs is unlimited, as EKPC argues, is a matter of contract interpretation that is beyond the scope of this proceeding, and is also the subject of litigation in Docket No. ER02-2560-002.

(2) Parties' Exceptions

200. EKPC argues that the Findings of Fact incorrectly conclude that the determination of whether the source points available to it under these GFAs is beyond the scope of this proceeding. EKPC asserts that it presented unrebutted evidence that the source points under their agreements are unlimited. EKPC argues that the GFAs' silence on source points indicates that it should have access to unlimited source points.

201. LG&E argues that the Findings of Fact correctly determined that EKPC has historically served its load from EKPC's own generation in its control area. Therefore, LG&E argues that the Findings of Fact should have found that the contract limits the source points to EKPC's own generator in its control area.

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background and experience (www.ferc.gov – click on Sitemap, then Office of Administrative Law Judges).

(3) Commission Discussion

202. For purposes of this proceeding, the parties to these GFAs have provided information for historic source and sink points, consistent with the Procedural Order. Since this historical data is sufficient for us to determine the proper treatment of GFAs under the TEMT. Any dispute regarding source points in these contracts in the future is, as the presiding judges correctly point out, a contract interpretation issue that is outside the scope of this proceeding. The Midwest ISO will use the historical information provided in incorporating transactions under these GFAs into the Energy Markets, depending on the standard of review.[167]

(k) GFA No. 293

203. GFA No. 293 is a long-term transmission service agreement between Northwestern and Dairyland. This contract allows each party to transmit over the others' transmission system subject to available capacity. Under this contract, the disputed transactions involve Dairyland's transmission across Northwestern's system to serve Dairyland's load in Grantsburg Wisconsin (Grantsburg load). Dairyland is not a member of the Midwest ISO, but Northwestern is. Consequently, service provided by Northwestern to Dairyland over Northwestern's facilities will be service over Midwest ISO facilities and subject to the TEMT. However, service provided by Dairyland to Northwestern over Dairyland's facilities will not be service over Midwest ISO facilities and therefore will not be subject to the TEMT.

204. The presiding judges stated that Dairyland is utilizing and deriving benefits from the Midwest ISO grid and therefore, under Commission precedent, Dairyland should be the Responsible Entity. However, the presiding judges found that since Dairyland is not a member of the Midwest ISO, Northwestern should be designated as the GFA Responsible Entity and GFA Scheduling Entity for Dairyland's use of Northwestern's system.

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[167] We note that parties agree to the standard of review applicable to GFAs Nos. 220 and 221. GFA No. 221 and the service applicable to loads in excess of base load amounts under GFA No. 220 are subject to a just and reasonable standard of review. Service applicable to base load amounts under GFA No. 220, the parties have explicitly provided, are subject to the *Mobile-Sierra* public interest standard.

(1) Parties' Exceptions

205. Northwestern argues that since Dairyland receives the benefits from the Midwest ISO grid, Dairyland should be the GFA Responsible Entity, even though it has not applied to Midwest ISO to become a Market Participant. Northwestern asserts that since Dairyland will benefit from the Midwest ISO Energy Markets, it should assume financial responsibility under the TEMT for its transactions under the GFA.

206. Northwestern also argues that Dairyland should be the GFA Scheduling Entity for this GFA since Dairyland is better positioned to be the GFA Scheduling Entity and has, or will have, the resources to schedule its own load. Northwestern states that its load is located in the Northern States Power Company (NSP) control area and NSP schedules for Northwestern. Northwestern also states that Dairyland operates it own control area and receives hourly load information from its load on Northwestern's transmission system that Northwestern does not receive. Furthermore, Northwestern states that Dairyland will also be scheduling its non-GFA load with the Midwest ISO, and Dairyland exchanges scheduling information with NSP regarding its load on Northwestern's transmission system. Therefore, Northwestern argues, since it is not and will not be scheduling its own load, and Dairyland will be, Dairyland is in a better position to act as the Scheduling Entity for this GFA.

207. Regarding the standard of review applicable to this GFA, Northwestern argues that Commission precedent requires parties to specifically state that the public interest standard applies to contract modifications and, if the contract is silent, the just and reasonable standard of review applies since neither party waived its unilateral filing rights. Furthermore, Northwestern argues that since GFA No. 293 has an indefinite term, only subject to termination on 48 months notification, it is likely that either party would apply for a rate change especially in light of the evolving energy markets and the need to adequately allocate costs due to changed circumstances.

208. Dairyland supports the presiding judges' finding that Northwestern should be the GFA Responsible Entity and the GFA Scheduling Entity since Dairyland is not, and does not intend to become, a member of the Midwest ISO. Dairyland contends that it does not need to take service from the Midwest ISO to utilize the transmission service it receives from Northwestern. Furthermore, Dairyland argues that the presiding judges misapplied Commission precedent by requiring the transmission customer to be responsible for charges that the GFA Responsible Entity would be obligated to pay under the TEMT.

(2) Commission Discussion

209. Since this contract is silent as to the appropriate standard of review and the parties still dispute which standard should apply, consistent with the approach adopted above,

this contract will be included in the group of GFAs that will be carved-out of the market. Therefore, we do not need to reach the question of which standard would, in fact, apply here; nor do we need to reach a determinations of the other disputed findings.

(l) GFA Nos. 352, 354, 365, 393, and 431

(1) Parties' Exceptions

210. MMTG argues that, contrary to the Findings of Fact, there is no factual basis for finding that the MMTG GFAs will burden the Midwest ISO's transmission system or markets or that the public interst necessitates modification of MMTG's GFAs. MMTG argues that its GFAs provide for long-term transmission service for fixed amounts of power from WAPA to specific loads under preset terms and prices. MMTG argues that transactions under these contracts are currently subject to less cost variability than market transmissions pursuant to the TEMT and that the market costs will be disproportionately burdensome to small entities such as MMTG. MMTG argues that since the total MMTG contracts are less then 25MW and individually range from 2 MW to 14 MW, maintaining the existing contract terms will not burden the Midwest ISO's transmission system to substantiate a public interest finding to substantiate modification of these contracts, even if others are modified.

211. MMTG states that contrary to the Findings of Fact, Sleepy Eye, Minnesota, did participate in the hearing through Witness Donald S. Kom's testimony that Sleepy Eye is GFA No. 393, the maximum MW transmitted under this GFA is 2.5 plus losses, that the GFA Responsible Entity should be WAPA, the source is WAPA and sink is CMMPA, and that the *Mobile-Sierra* standard of review should apply.[168]

212. MMTG agrees with the Findings of Fact that WAPA should be the GFA Scheduling Entity, but argues that WAPA, not Xcel, should be the GFA Responsible Entity for these contracts since WAPA generates and schedules the power.

(2) Commission Discussion

213. As an initial matter, GFA No. 393 was excluded from this proceeding by the presiding judges' order dated July 15, 2005. Since we are affirming this exclusion, the exceptions to GFA No. 393 are moot. For the remaining GFAs, MMTG argues that the public interest standard of review cannot be met and therefore its GFAs should be allowed to continue as before. The parties to GFA Nos. 365 and 431 have explicitly

[168] MMTG brief at 17 (*citing* Tr. 747:24-48:14, 764:9).

provided that they are subject to the *Mobile-Sierra* public interest standard of review, and as described above, we are requiring the Midwest ISO to carve these GFAs out of the market. Therefore, we need not address MMTG's exceptions regarding these GFAs. GFA Nos. 352 and 354 are subject to a just and reasonable standard of review, and we therefore are treating these GFAs in a manner consistent with that standard, as we describe above. Thus, MMTG's argument regarding the public interest standard is moot with respect to these contracts. The relative size of the load served does not affect our determination since we must consider them in the context of the larger sub-set of non-settling GFAs subject to a just and reasonable standard of review. Finally, the exceptions related to the GFA Responsible Entity and GFA Scheduling Entity have already been addressed generically above.

(m) <u>GFA No. 374</u>

(1) <u>Presiding Judges' Findings of Fact</u>

214. GFA No. 374 involves a 20-year contract entitled "Arpin Substation Benefit Area Joint Operating, Planning and Cost Sharing Agreement" (Arpin Agreement). The parties to this agreement include Northern States Power Company – Wisconsin and Northern State Power Company – Minnesota (together, Xcel), Wisconsin Power & Light Company (WPL), WPS Resources, and Marshfield Electric and Water Company (MEWD).[169] In their Findings of Fact, the presiding judges found that, under this GFA, Xcel provides transmission service over certain Midwest ISO-controlled facilities to WPL, WPS Resources, and MEWD for service to their loads in the Central Wisconsin System. They also found that WPS Resources and WPL should be the GFA Responsible Entities for their respective transactions under GFA No. 374. The parties agree that modifications to the contract are subject to the just and reasonable standard of review.

(2) <u>Parties' Exceptions</u>

215. WPS Resources and Alliant, on behalf of WPL, jointly filed exceptions to the presiding judges' finding that the Arpin Agreement provides for transmission service and therefore should not be excluded from this proceeding. They argue that the Arpin Agreement is a facilities support agreement that provides for an equitable sharing among WPS Resources, WPL, and Xcel, of costs associated with facilities necessary to interconnect their transmission systems and provides certain operating limitations to ensure reliable interconnected operations of the utilities. WPS Resources and Alliant

[169] Wisconsin Electric is an additional signatory, but not a party, to GFA No. 374. Exh. XES-1 at 39.

state that they take all of their transmission service over the Arpin Substation and related facilities pursuant to the Midwest ISO Tariff, and this service will be fully subject to the Midwest ISO Energy Markets. According to WPS Resources and Alliant, even before the advent of the Midwest ISO Tariff, the Arpin Agreement was not a basis for providing transmission service. They conclude that the Arpin Agreement does not provide a basis for allocating FTRs, has nothing to do with the Midwest ISO Energy Markets, and therefore, should have been excluded from these proceedings. They argue that the presiding judges excluded other similar agreements from the proceeding and should have excluded this agreement as well.

(3) Commission Discussion

216. The Arpin Agreement provides for interconnection of the parties' transmission systems and establishes financial responsibility for the costs of the interconnection facilities and operating restrictions on the parties in order to prevent or relieve overloading of the facilities or reduced system reliability. Xcel and WPS Resources and Alliant agree that: (1) no transmission service is scheduled under the agreement;[170] and (2) the agreement does not provide a basis for all allocating FTRs.[171] Further, the parties take all of their transmission service over the interconnection facilities under the Midwest ISO Tariff and such service will be subject to the Midwest ISO Energy Markets, including Schedules 16 and 17 of the Midwest ISO Tariff.

217. Given these facts, we find that the Arpin Agreement, as currently used in practice, does not provide for transmission service that will impact Midwest ISO's Energy Markets. However, based on the record before us, we cannot determine whether the Arpin Agreement could be used in the future to provide transmission service that will impact Midwest ISO's Energy Markets. Therefore, we will set this issue for hearing. In the meantime, for initial treatment of this GFA upon the commencement of Midwest ISO's markets, the MWs associated with this contract should be zero for the purpose of FTR allocation, and the parties should conduct no transactions under the contract, consistent with the parties' current practice to not transact under this agreement. Consistent with our findings above regarding the designation of GFA Responsible Entity and GFA Scheduling Entity where the GFA parties disagree on those designations, Xcel is the GFA Responsible Entity and GFA Scheduling Entity. We note that these

[170] *See* WPS Resources and Alliant brief at 14; Xcel's July 21, 2004 response to WPS Resources Late-Filed Testimony at 5.

[171] *See* WPS Resources and Alliant brief at 10; Xcel's July 21, 2004 response to WPS Resources Late-Filed Testimony at 8.

designations will be of no practical effect for the time being as no transactions will take place under, and no FTRs will be associated with, this GFA.

6. **Other Commission Findings**

218. We affirm and adopt all of the orders issued by the presiding judges that excluded, with the Midwest ISO's concurrence, certain GFAs from this proceeding.[172] We will address whether these and other GFAs should be included in Attachment P to the Midwest ISO Tariff in the last section of this order.

219. Given the total number of GFAs at issue in this proceeding, the number of filings related to each GFA, and the total amount of data involved in this proceeding, we do not address in the body of this order every issue related to each GFA and the information submitted. To the extent we do not specifically address in the body of this order a concern raised about a particular GFA, our determination on the issue is contained in the information listed in Appendix B to this order. Appendix B outlines our findings regarding the maximum number of megawatts as well as the responsible entity and the scheduling entity for each GFA. To the extent this information is the same as reported in the Findings of Fact, we adopted the presiding judges' findings. To the extent that information differs from that reported in the Findings of Fact, we adopt the finding listed in Appendix B to this order. Where information in Appendix B differs from the Findings of Fact or from the information in the joint filings submitted by the parties, we have included an explanation of our rationale for each such Appendix B finding. We also adopt the source and sink information as reported in the Findings of Fact and those that were agreed to in jointly filed templates.

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[172] These include GFA Nos. 1,10, 13, 15, 18, 21, 22, 23, 24, 25, 26, 27, 32, 33, 37, 38, 40, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 93, 99, 113, 114, 115, 116, 117, 118, 119, 120, 121, 122, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 138, 139, 140, 143, 148, 149, 150, 151, 153, 154, 155, 156, 157, 158, 160, 180, 181, 184, 187, 191, 193, 194, 195, 196, 197, 198, 199, 201, 202, 203, 204, 208, 217, 218, 226, 227, 228, 229, 230, 231, 232, 233, 234, 235, 236, 237, 238, 239, 240, 241, 242, 243, 244, 245, 246, 247, 248, 249, 250, 251, 252, 253, 258, 259, 260, 261, 262, 263, 264, 265, 270, 271, 272, 275, 276, 277, 278, 279, 280, 281, 282, 283, 287, 288, 290, 292, 294, 295, 296, 298, 299, 301, 303, 305, 307, 310, 312, 315, 319, 322, 325, 326, 327, 328, 329, 330, 339, 340, 345, 348, 349, 350, 351, 353, 356, 380, 393, 396, 397, 398, 400, 402, 404, 408, 429.

220. As to the finding required for maximum number of MW transmitted pursuant to each GFA, we adopt a generic approach if the GFA has no stated MW amount. For contracts for which three years of historical data is available, we find that the largest capacity figure in the three-year period is the correct number to use for the maximum MW transmitted. We believe this finding errs on the side of conservative treatment of the GFAs and best preserves the bargain inherent in GFAs that do not contain stated capacity. We direct the Midwest ISO to use the "Maximum MWs Transmitted Under GFA" stated in Appendix B, along with the source and sink information provided in the Findings of Fact and the jointly filed templates, to account for these GFAs in its model developed for the initial FTR allocation. More specifically, when accounting for GFAs in its FTR model, the Midwest ISO should use these capacity amounts: (1) as the upper limit for allocating FTRs to GFA parties whose contract has a just and reasonable standard of review and who select Option A; (2) as the upper limit for GFA transactions that are carved out of the Midwest ISO markets; and (3) as the capacity reserved under the three options for settling GFA parties. Although the Midwest ISO, in its proposal to incorporate the GFAs, proposed that the GFAs file "[t]he source and sink points applicable under the Grandfathered Agreements,"[173] we believe that the Midwest ISO may require more detailed information regarding the capacity between nodes to be reserved for the GFAs given the level of detail in its system model. Also, we believe that the Midwest ISO may require historical capacity used on a seasonal basis in order to model the GFA usage on a seasonal basis. We therefore direct parties to the GFAs, working within the findings listed in Appendix B to this order, to timely provide more detailed data at the request of the Midwest ISO. Parties that do not comply with such a request risk having a smaller number of MW or inappropriate nodes set aside for their transactions under their GFAs when the Midwest ISO begins allocating FTRs this October. We also note that parties to GFA No. 409 provided MWh usage. We direct these parties to provide to the Midwest ISO the maximum integrated hourly megawatt value for power actually transmitted pursuant to GFA No. 409 during the last three years.

221. Where more than one GFA covered the same service, we only reported the megawatts once to avoid-double counting. The notes for these GFAs will list the related GFA numbers.

222. If parties agreed that the contract was subject to a mixed standard of review, *i.e.*, some parts of the contract are subject to a just and reasonable standard and other parts subject to a public interest standard, we find that the contract is subject to a *Mobile-Sierra* public interest standard of review for purposes of classifying it for this proceeding.

[173] Midwest ISO Tariff at 38.2.5.j(iii).

223. We direct the Midwest ISO to file revised tariff sheets, within 30 days of the date of this order, reflecting the modifications to the Midwest ISO's proposed treatment of GFAs adopted in the Procedural Order (*e.g.*, rejection of the process proposed in Module A, Section 12A, and Module C, Section 38.2.5.j) and in the instant order. These revisions should clearly identify, for each GFA, the treatment adopted in this order (*i.e.*, either converted to TEMT service or subject to a choice among Options A, B, or C pursuant to a settlement of GFA treatment approved in this order, subject to a choice among Option A or Option C because the GFA is subject to the just and reasonable standard of review, subject to a carve-out from the Midwest ISO Markets, or excluded from this proceeding).

D. Midwest ISO's FTR Options under the TEMT and Settlements

1. Background of the Midwest ISO's Proposed Options A, B and C

224. In the Procedural Order, the Commission, among other things, suspended the tariff sheets relating to the Midwest ISO's proposed treatment options for GFAs, but did not prejudge their merits.[174]

225. The Midwest ISO's proposed TEMT requires parties that did not voluntarily convert their GFAs to TEMT service to select from among three options – to remain in place for a three-year transition period that would end coincident with the six-year transition period initially approved in 1998[175] – that would determine the treatment of their GFAs in the Energy Markets.[176]

226. Under Option A, the GFA Responsible Entity would be entitled to nominate the capacity under the GFA for an allocation of FTRs. It would hold the FTRs it receives in the allocation and assume responsibility for credits, debits, rights and responsibilities

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[174] Procedural Order at P 3.

[175] *See* Formation Order at 62,167, 62,169-70.

[176] *See* Module C, Section 38.2.5.j, Original Sheet No. 402. All three options for unconverted GFAs would require the parties to submit to the Midwest ISO the following GFA information: (1) the name of the GFA Responsible Entity;[176] (2) the name of the GFA Scheduling Entity; (3) the source and sink points applicable to the GFA; and (4) the maximum megawatt capacity permissible under the GFA.

associated with those FTRs. The Midwest ISO would assess congestion charges and the cost of losses for all transactions under the GFA.[177]

227. Option B provides that the GFA Responsible Entity will not nominate or receive FTRs.[178] The Midwest ISO will charge the GFA Responsible Entity the cost of congestion for all transactions pursuant to the GFA, but – if the GFA Scheduling Entity submits the bilateral transaction schedule a day ahead, in keeping with section 39.1.4 – the Midwest ISO will credit back to the GFA Responsible Entity the costs of congestion resulting from day-ahead schedules that the GFA Responsible Entity clears in the day-ahead market.[179] The Midwest ISO will also charge the GFA Responsible Entity the cost of losses for all transactions under the GFA, then – as before, if the GFA Scheduling Entity has timely submitted a conforming schedule for the GFA – credit back to the GFA Responsible Entity the difference between marginal losses and system losses at the GFA source and sink points.[180]

228. Market Participants that select Option C will neither nominate nor receive FTRs. Instead, the GFA Responsible Entity will pay marginal losses and the cost of congestion for all transactions pursuant to GFAs without receiving reimbursements as in Option B. However, the GFA Responsible Entity will receive an allocation of excess marginal losses revenue based on their share of the marginal losses pool.[181]

229. Market Participants with GFAs that select Option A convert their rights to transmission service under the GFA to Candidate Financial Transmission Rights (CFTRs)

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[177] *See* Module C, section 38.8.3.a, Original Sheet Nos. 445-46.

[178] *See* Module C, section 38.3.3.b.i, Original Sheet No. 447.

[179] If a revenue inadequacy results, the Midwest ISO will compensate the GFA Responsible Entity for the costs of congestion by assessing debits on all Market Participants on a *pro rata* basis. *See* Module C, Section 38.8.3.b.ii, Original Sheet Nos. 448-50.

[180] The TEMT states that the Midwest ISO will determine the difference between marginal losses and system losses "on an equitable basis." Module C, section 38.8.3.b.iii, Original Sheet No. 451. The Midwest ISO further notes that this mechanism will be different from the mechanism used to refund over-collections of loss revenues to parties to non-GFA transactions. *See* Transmittal Letter at 14.

[181] *See* Module C, section 38.8.3.c, Original Sheet Nos. 452-53.

obligations.[182] The Midwest ISO has proposed to make CFTRs available based on a multi-tiered allocation/nomination methodology. Parties with FTRs granted under Option A will be considered along with parties converting existing OATT service to FTRs in the allocation.[183] Option B GFAs will have obligation FTRs corresponding to the points of injection and withdrawal in the GFA modeled in the FTR allocation; these FTRs will have priority in the tiered allocation process.[184]

230. The Midwest ISO submitted the direct testimony of Dr. William Hogan with its March 31, 2004 TEMT filing. Dr. Hogan discusses the merits of the GFA options that the Midwest ISO proposes throughout his testimony. Numerous intervening filed parties responses.

231. Dr. Hogan describes Option A as the next best option to full conversion to the TEMT, as GFA transactions would receive the same treatment as non-GFA transactions regarding scheduling and transmission usage charges, including congestion and marginal losses. The main distinction he notes is that the transmission customer who selects

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[182] *See* Module C, section 43.1.2.a, Original Sheet No. 605.

[183] According to Module C, section 42.2.4, Original Sheet Nos. 613-625, Market Participants under existing Midwest ISO Tariff service are eligible to nominate FTRs up to the total of forecast peak load served under network integration transmission service and the total MW in existing point-to-point transmission service. The GFA holders that select Option A will jointly nominate FTRs with these other Market Participants. All entities with CFTRs will be allowed to nominate a percentage of their total eligible quantity in four cumulative tiers: up to 35 percent in Tier I, 50 percent in Tier II, 75 percent in Tier III, and 100 percent in Tier IV. FTRs not awarded in one tier can be renominated in the next tier. Following Tiers I and II, nominated FTRs that would have been feasible if another party had nominated a base-load FTR that provided needed counterflow can be restored through the assignment of counterflow FTRs to the latter party as listed in Module C section 43.2.5, Original Sheet Nos. 626-629. We note that some TEMT-FTR allocation rules were modified in the TEMT II Order.

[184] CFTRs equal to 100 percent of the full MW quantity of the Option B GFAs are automatically included in Tier I, and, although the Midwest ISO will not actually issue FTRs to the GFA holders that select Option B, they must account for them when conducting the simultaneous feasibility test. FTRs allocated to Option A GFAs may also be nominated in addition to the Option B GFAs up to the tier I cap, but where the Tier I cap is exceeded, only Option B GFAs are accepted and the size of the nomination eligibility in subsequent tiers is reduced accordingly.

Option A is getting a "one-year taste" of voluntary conversion while retaining its right to pick from among the other options in later years of the transition period.

232. Dr. Hogan describes Option B as premised on the idea of making GFA parties financially indifferent to the LMP-based charges for congestion and marginal losses in the Day-Ahead Energy Market, provided they comply with scheduling requirements. Under Option B, the transmission rights contained in the GFA are in effect accommodated as firm service through the Midwest ISO's security-constrained economic dispatch. The Midwest ISO will keep the GFA financially indifferent to the costs of congestion by crediting the GFA transaction at settlement as though the scheduling party had a perfectly matching set of FTRs, thus providing a perfect hedge. To achieve the effect of charging the GFA average, rather than marginal, losses, the Midwest ISO would rebate the difference between the actual marginal losses included in the transmission usage charge, and the Midwest ISO's calculation of average losses. Dr. Hogan notes that it is not clear how the Midwest ISO will implement this marginal loss rebate provision, but nevertheless concludes that it will provide a "substantial benefit" to parties that choose Option B.

233. Dr. Hogan further discusses significant additional benefits for GFA parties that could be achieved under Option B through scheduling provisions that negate the "use-it-or-lose-it" feature of the physical transmission right. He concludes that the GFA customer would have a strong incentive under Option B to schedule all of its physical rights in the Day-Ahead Energy Market whenever it expects congestion in the Real-Time Market. Then, in real-time, if the congestion materializes as planned, the GFA customer incurs no cost for the schedule and is in effect paid to reduce its schedule in the Real-Time Market to match its actual power flow. The Transmission Owner has shifted its redispatch obligation onto the Midwest ISO. Dr. Hogan states that the risk that the congestion cost would reverse from the GFA's expectation would be rare and, on average, the GFA should benefit from the value of the implicit FTR. To minimize the side effects of Option B on other Market Participants, Dr. Hogan asserts that it is essential for the Commission to allow virtual bidding for all parties including GFAs.

234. Dr. Hogan characterizes Option C as a reasonable approach to minimize the risks that the GFA Responsible Entity would assume under certain generation/load configurations if they were required to accept counter-flow FTRs under the Midwest ISO's FTR allocation rules.

(a) <u>May Comments on the Midwest ISO's March 31, 2004 TEMT Filing</u>

235. Basin, *et al*. support the use of Option B and argues that the Commission should resist other intervenors' assertions that the Commission should reject or modify

Option B. Likewise, they argue that the Commission should not agree with the testimony of Dr. Hogan, where it discusses Option B, because it ignores important benefits that Option B provides to GFA and non-GFA customers. Basin, *et al*. asserts that Option B provides benefits to the overall market by reducing costs for GFA parties to participate in the Energy Markets. By reducing costs Option B ensures that the incentives are there for greater GFA participation, which adds to reliability and economic efficiency. Therefore, they conclude that the small amount of uplift associated with Option B is justified because it is outweighed by the overall benefits to all Market Participants.

236. Consumers argues that it is unclear if the Midwest ISO intends to fund the cost of the congestion credit through a region-wide uplift charge in sections 38.8.3.b (i) and (ii) of the TEMT. It is similarly unclear if the marginal to average loss crediting methodology will use uplift to pay for refunds between marginal and average losses in section 38.8.3.b (iii) of the TEMT.

237. Numerous commenters requested that the Commission reject some or all of the GFA options provisions because they do not do enough to preserve existing rights. For example, the NRECA does not believe that the Midwest ISO "paid heed to the Commission's preference that the 'phantom congestion' problems identified by the Midwest ISO be addressed 'in a manner consistent with contractual rights.'"[185] It asks that the Commission reject the proposal for GFAs because it does not preserve existing contract rights. The Municipal Participants argue that Option B does not hold parties economically indifferent. The Municipal Participants further state that by electing one of the options, GFA parties will forego their physical contract rights that provide benefits that they do not necessarily have to forego.

238. Dairyland argues that none of the Midwest ISO's three options does enough to ensure that GFA parties are kept financially indifferent from the impacts of the Energy Markets. Dairyland dismisses the comments of Dr. Hogan that GFA parties will be better off financially under Option B because they contend that he ignores additional risks and costs that do not exist without the Energy Markets. Instead of the Midwest ISO's proposed options, Dairyland asserts that a modified physical carve-out may be a viable option for GFAs where the Midwest ISO exempts GFAs from congestion, marginal losses, energy imbalance costs, and Schedule 16 and 17 costs in exchange for a requirement that the GFA parties register with the Midwest ISO and submit hourly schedules in the day-ahead market.

[185] NRECA May Comments at 27 (*citing* TEMT I Order at P 60).

239. Detroit Edison has similar concerns as Dairyland that none of the options is sufficient, but if forced to choose they would likely pick Option B. However, they are concerned that Option B will not provide equivalent rights to the GFA contracts Detroit Edison possesses today, particularly for its Ludington pumped storage facility.

240. Crescent Moon Utilities argue that although none of the Midwest ISO's proposed options should be accepted by the Commission, Option B does not impose unreasonable cost shifts onto third parties. In their view, Option B recognizes that there is an implicit trade-off between GFA and non-GFA parties in that non-GFA parties obtain the benefits of the Day 2 markets that would not be feasible without GFA participation. However, in order to achieve the benefits of Day 2 markets, non-GFA parties must share in uplift to maintain the benefits of the GFA contracts. Crescent Moon views Options A and C as particularly damaging because they require load to bear the costs of congestion and losses. Therefore, they recognize Option B as the least offensive of the three options to the Crescent Moon contracts.

241. Otter Tail agrees with Crescent Moon that, provided the Commission does not reject the proposed treatment of GFAs, any uplift associated with Option B should occur on a market-wide basis and not at the control area level. Otter Tail states that the Midwest ISO should amend section 42.2.4.a.ii of the TEMT to clarify that Option B will only count against a company's Tier I FTR allocation if those GFAs taking Option B are serving that company's network load. Furthermore, in the event that a company becomes a responsible entity for grandfathered service it is providing to another company, the service to that other company should not be counted against the transmission providing company's Tier I allocation.

242. Minnkota argues that Otter Tail's entry into the Midwest ISO should not abolish its agreement with Otter Tail to use the each other's higher voltage transmission facilities (and vice versa) without charge. Minnkota argues that such a change would give rise to lower quality of service and higher rates, which would not be justifiable under the "just and reasonable" or "public interest" standards. Minnkota asserts that the Midwest ISO has produced no evidence that the public interest will be harmed if Minnkota's GFAs are not modified, and therefore, the Midwest ISO's proposal must be rejected. However, Minnkota does not believe it is subject to the terms outlined in the three options, and therefore will not choose between them. Minnkota asks for protection until February 1, 2008 from congestion charges that are equal to what it enjoys today under its GFAs.

243. Minnesota Municipal protests all of the options proposed for GFAs because they view them as options that will materially change their existing agreements, especially if Option B is only available until February 1, 2008. To the extent that the terms of

Minnesota Municipal's GFA are modified, including duration, they contend that constitutes a violation of the *Mobile-Sierra* doctrine. Therefore, they request that if the options are retained that they be exempt from any financial risks caused by the new markets until the contracts expire in 2012.

244. The Midwest TDUs filed comments that state that although Option B comes closer than Option A or C to preserving existing rights under the GFAs it still fails to sufficiently honor existing contract rights. They argue that the Midwest ISO's proposal to credit back Option B customers the difference between marginal and system average losses is unclear and impossible to implement given the current lack of detail in section 38.8.3.b.iii of the TEMT. Regardless, the Midwest TDUs are clear that the system will not preserve the exact loss terms specific to the original contract under the Option B proposal. Secondly, they argue that the proposal to provide a hedge for congestion costs in Option B only applies to schedules that are not changed after the day-ahead scheduling deadline, so the GFA could be exposed to un-hedged congestion costs, which they argue is contradictory to the goal of preserving existing contract rights as stated in the prior TEMT Order. They are also concerned with the FTR allocation process and the loss application methodology applied to schedules changed after the day-ahead scheduling deadline.

245. WPS Resources believes that the GFA proposal favors GFA parties at the expense of the majority of the Midwest ISO's load. Accordingly, WPS Resources recommends that the Commission should limit GFA parties to Option A or allow all load to utilize Option B.

246. Other comments conclude that Option B extends to GFA parties financial rights beyond what they currently possess and pays for those extra financial rights through uplift. PSEG asks the Commission to eliminate Option B because it would provide benefits to transmission customers in excess of those necessary to promote their "financial indifference." However, Reliant argues that the Commission should reject the Midwest ISO's options proposal entirely because Option B forces others to bear the cost of these additional rights through uplift charges. To minimize the potential for uplift, FirstEnergy argues that the Commission should hold that the public interest requires GFA parties to abide by the TEMT. Since GFA parties will receive added benefits by transacting in the new Energy Markets, they should bear the additional costs themselves and not the Market Participants of the region.

247. Cinergy and the EPSA are likewise concerned that Option B not only preserves the benefits of the GFAs, but also expands GFA parties' benefits leaving them better off than they are today. Therefore, they argue that the Commission should reject Option B. To support their position that Option B should be rejected, Cinergy cites the testimony of the Midwest ISO's witness Dr. Hogan. Throughout his testimony, Dr. Hogan references

Option B as an option that will create added benefits for both parties to the GFA, shift

costs away from the GFA parties, and distort incentives for accurate scheduling in the day-ahead market.[186]

248. Alliant comments that the options proposal grants GFA holders special treatment beyond that granted to OATT service that will result in large cost uplifts and economic inefficiencies. It recommends that GFAs should be treated in the same manner as network and point-to-point transmission service contracts. If the Commission does not adopt that methodology, it recommends that the Midwest ISO not allow nominations of FTRs for Option B to exceed the tier I limit to minimize the amount of prorating of FTRs in later tiers.

249. OMS argues that the Commission should direct that the Midwest ISO's nomination of FTRs for retained GFAs not to exceed the corresponding tier limits. The OMS contends that if the FTRs set aside for all Option B GFAs are nominated in the first tier regardless of whether or not this exceeds the 35 percent tier limit it will likely result in FTR prorating for non-GFAs in the first tier and all parties in the second tier. If this prorating is significant, it is not clear that requiring counter-flow FTRs from base-load resources will provide sufficient FTRs to keep the congestion costs of those holding existing firm transmission rights at current levels. The OMS feels that not allowing the FTRs for Option B GFAs to exceed the tier limits more fairly uplifts the costs of allowing transmission customers to retain their GFAs rather than imposing those costs on specific transmission customers who did not cause them. In other words, it will allow for a greater cost causation connection.

250. OMS states that treating GFAs the same as other network transmission service customers is the best alternative to special treatment. However, they acknowledge that in the transition period to new markets some compromises must be made and they accept section 38.8.4 that states that the special treatment afforded GFAs in section 38.8 "shall terminate no earlier than February 1, 2008."[187] To evaluate what the effect of granting different treatment for GFAs beyond February 1, 2008 would be, they recommend that the Commission open an investigation to determine the impact of the GFAs' special treatment on other market participants and the efficiency of the Midwest ISO Energy Markets. This investigation should determine whether special treatment beyond the end of the transition period on February 1, 2008 is just and reasonable. However, the OMS

[186] *See* Hogan testimony at 9, 16-20, 37-38, and 40-51.

[187] *See* Module C, Original Sheet No. 454.

notes that North Dakota, Wisconsin, Iowa, Minnesota, and Montana do not agree with an investigation of this nature at the present time because they believe it would be premature and would undercut the stakeholder process.

251. WPPI argues that designating long-term firm service under the OATT for network resources as inferior to GFA contract service through the options proposal would be unjust, unreasonable, unduly discriminatory and anticompetitive. They argue that RTO history shows that entities that resist FERC policies and avoid RTO markets benefit in the long run. As proof they state that the recalcitrant are now in a much more secure position to meet their service obligations than those that worked with FERC to start these markets, such as WPPI. Going forward, WPPI states that the Commission needs to make it clear that utilities will not be punished for cooperating with FERC policy initiatives. Finally, WPPI also asks that the GFA cost protection extend for the life of the contract and not end at the 2008 deadline.

252. The WUMS Load-Serving Entities argue that they voluntarily sacrificed GFA protection under the Midwest ISO TEMT by divesting their transmission assets to American Transmission Company LLC, and as a consequence, they will be net payers of uplift under the proposed GFA optional treatment. They further argue that the Midwest ISO assumes that all parties to existing GFAs will choose to take the Option B treatment.

(b) June Comments Responding to Paragraphs 72-74 of the Procedural Order

253. If the Commission does not adopt their carve-out proposal, the Midwest ISO TOs offer two alternative proposals for GFA treatment under the TEMT. Under the first alternative proposal, GFA parties would not be subject to the congestion management provisions of the TEMT, but would pay for any imbalances based on real-time LMP prices, provided that the Commission adopts a tariff mechanism to permit recovery of the costs associated with imbalances. They propose that, if the GFA customer agrees to provide the scheduling information, the customer submits the schedule to the Midwest ISO and pays the costs of the imbalances. If the customer does not agree to provide such information, the GFA Transmission Owner submits the schedule, but the customer must then pay any imbalance costs under the proposed tariff provision.[188] A second option offered by the Midwest ISO TOs would be to maintain all the elements of the first option, except that congestion-associated deviations from day-ahead schedules would be managed under the LMP system.[189] The Midwest ISO TOs state that adopting this

[188] Midwest ISO TOs' June Comments at 23.

[189] *Id*. at 24.

approach will eliminate the need to determine whether hundreds of GFAs require modification in order to accommodate the Midwest ISO's Energy Markets.

254. In Cinergy's June Comments, it argues that Option B is harmful to third parties and must be rejected because it would excuse GFA service providers from the cost of congestion and redispatch, causing those costs to be borne by others. It explains that FTR inefficiencies will result from greater risk premiums being placed on FTR acquisition due to the reduced ability to provide a perfect hedge from day-ahead spot market impacts. Cinergy states that Option B also provides an incentive for over-scheduling, that parties could profit from, because GFA customers would receive a full rebate for all of the transmission scheduled, including unused portions.

255. In support of its positions, Cinergy submitted the testimony of Dr. Richard Tabors. Dr. Tabors concluded that the use of Option B in lieu of a physical carve-out is not a reasonable alternative because it will lead to discrimination, market inefficiencies, and reliability concerns similar to those associated with the carve-out approach. Dr. Tabors explains that GFA parties will receive a full hedge of their congestion costs, while the non-GFA parties will receive under-valued, under-funded FTRs, and a share of the uplift costs needed to credit participants that take Option B back their congestion costs and the difference between marginal and average losses. He states that FTRs will likely be under-funded and under-allocated because the Midwest ISO must estimate in its FTR allocations the amount of transmission capacity to set aside for GFA transactions to ensure they pass the SFT. To address what he describes as a "fundamental discrimination" inherent in Option B, he recommends that the congestion credit be put on par with the actual FTR value.

256. Dr. McNamara also concluded that having the Midwest ISO set aside an appropriate set of FTRs in the FTR allocation process to account for the transmission that is likely to be used by GFA transactions could result in financial advantages for GFA parties that select Option B.[190] He determined that this could occur if the Midwest ISO assigns the GFA schedules fewer or less valuable FTRs than are needed to hedge the actual GFA transmission schedules, but still credits the GFAs as if they had a perfect congestion hedge under Option B. Another scenario under Option B envisioned by Dr. McNamara is if the Midwest ISO assigns too many FTRs to the GFA schedules, it would reduce the total number of FTRs that could be allocated to other parties, making them less than fully hedged against congestion. Thus, non-GFA parties would pay for making GFA parties financially indifferent to the costs of congestion and losses. In order to mitigate the cross-subsidy affect between non-GFA and GFA parties Dr. McNamara

[190] McNamara testimony at 36.

states that the Midwest ISO must have reasonably accurate information from GFA holders about the transmission schedules they actually expect to submit. However, he cautions that some degree of cost-shifts is inevitable as estimates of transmission usage are likely to be wrong to some extent.[191]

257. FirstEnergy is concerned that the use of Option B will shift costs to the entire Midwest ISO region. It states that the region will be forced to pay for GFA's FTRs and an increase in payments for losses through uplift charges. FirstEnergy asserts that the Midwest ISO has not quantified these costs under Schedule 16 and 17, and until power actually flows under the TEMT, the Midwest ISO will not be able to estimate its costs. Similarly, it states that the costs for marginal losses will not be known until actual losses are calculated. However, FirstEnergy believes that a cost-shift of "significant proportions" could occur.[192]

258. The Midwest TDUs argue that the Midwest ISO's proposed Option B will not result in undue discrimination against non-GFA holders. They assert that LSEs must still serve their load, and therefore face real-time LMP prices if they idle their GFAs. According to the Midwest TDUs, a GFA holder, who schedules day-ahead resources that it expects to idle anticipating counter-scheduling in the real-time market, would have to pay congestion charges on those counter-schedules if real-time congestion reversed. They also assert that one problematic part of the Midwest ISO's proposed Option B is that it inappropriately loads costs onto non-GFA customers, and thus discriminates against those competing for simultaneously feasible FTRs over the same flowgates. The Midwest TDUs contends that these charges should be uplifted broadly to avoid discrimination by an unfair delegation of costs.

259. In its June Comments, the OMS asserts that Option B provides GFA participants with an opportunity for economic gain with a subsequent uplift of costs to third party market participants. It states that, by allowing sellers to bypass congested lines and schedule anticipated GFA transmission in the day-ahead market, knowing the LMP at the load will be higher than at the point of generation, the seller is forgiven any congestion costs associated with the schedule. OMS asserts that, any excess scheduled energy not used by the GFA buyer can be resold in the real-time energy imbalance market, thereby allowing the seller to reap the benefits of the higher LMP price. Thus, according to OMS, the seller is allowed to recover real-time congestion cost differences between its generation sources and the GFA load destination. Further, OMS explains that, by over

[191] *Id*. at 37.

[192] FirstEnergy June Comments at 6.

scheduling in the day-ahead market, the congestion costs forgiven may amount to more

energy than is needed to fulfill the GFA, resulting in revenue shortages collected from FTRs compared to congestion costs forgiven for GFA schedules.

260. WPS asserts that the Commission should only approve Option A to limit the amount of cost shifts. It is concerned that the parties that choose Option B may not be responsible for their own excess congestion costs since, depending on the method of uplift allocation, these charges could be recovered from all other customers, including Option A customers. WPS states that, without knowing how FTRs or uplift charges will be allocated, it is unknown whether FTR revenue will be sufficient to offset congestion costs. WPS further contends that additional administrative costs associated with Option B cannot be assessed at this time. WPS stresses that allowing GFAs to operate in the Midwest ISO market, but shifting their portion of the costs to other customers, is the essence of undue discrimination.

261. LG&E asserts that the Midwest ISO's analysis fails to address the potential cost shifts associated with Options A, B, and C. Specifically, LG&E states that: (1) Option B is unacceptable because it socializes costs associated with day-ahead schedules across the Midwest ISO footprint; (2) Option C is unacceptable because it is impossible to determine its costs and benefits; and (3) Option A is problematic because under it the GFA Responsible Entity will be entitled to nominate the capacity under the GFA for an allocation of FTRs and will be subject to all Midwest ISO costs associated with the transaction. Option A may also reduce the amount of FTRs available to other parties. The potential for cost-shifting under the three options, and lack of knowledge about the GFA issues true scope, leads LG&E to the conclusion that it would be preferable to convert all GFAs to TEMT service from the outset.

(c) <u>Commission Discussion</u>

262. We accept the Midwest ISO's proposal for Option A treatment for GFAs as filed in section 38.8.3(a) of the TEMT.[193] We find the provisions that outline Option A are just and reasonable; as they are overwhelmingly similar to full conversion to the TEMT, which has previously been found to be just and reasonable.[194] GFA parties that select Option A will receive almost identical financial treatment as non-GFA parties in regards to scheduling, FTR allocations, and collections from the marginal losses revenue pool. In

[193] *See* Module C, Original Sheet Nos. 445-446.

this case, we agree with the testimony of Dr. Hogan who describes Option A as virtually

the same as, *i.e*., a "next-best" option to, voluntary conversion of a GFA to TEMT service.[195]

263. We likewise accept the Midwest ISO's proposal for Option C treatment for GFAs as filed in 38.8.3(c) of the TEMT. We find that the use of Option C is an acceptable option for those parties that take it. Accordingly, we find Option C to be just and reasonable.

264. As discussed below, we find Option B to be just and reasonable for those parties that voluntarily settled prior to July 28, 2004, in accordance with the Procedural Order,[196] but Option B will no longer be available for parties that did not settle by that date. Option B was an incentive to settle and receive a hedge against congestion and marginal losses charges. It would be unfair to allow this option to those that did not settle first and waited (and even litigated) the outcome of this proceeding. We accept that GFA parties that have settled prior to July 28th may pick among the three options on an annual basis as specified in section 38.2.5(j).[197] However, we direct the Midwest ISO to revise section 38.2.5(j) to state that only parties that settled may request a change in treatment of such agreements annually from among the three options as described in section 38.8.3. Market Participants that did not voluntarily settle may request a change of treatment annually between Options A and C, but they may not choose Option B.

265. We direct the Midwest ISO to evaluate any impacts that could be caused by annual switching among the GFA options. As a result of this evaluation, we direct the Midwest ISO to file with the Commission within 60 days a proposal to clarify section 38.2.5(j) that lists the date when such switching could occur. This evaluation should especially focus on synchronizing any ability to switch among the GFA options with the FTR allocation periods to avoid any timing conflicts, such as requests for changes in treatment in between FTR allocation periods. The date to allow changes in GFA treatment to occur should coincide with the date for redistributions of FTRs. However, the Commission will not unilaterally mandate a date on which any changes in the options may occur, given the

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[194] TEMT II Order at P 3 (2004).

[195] *See* Hogan testimony at 16 and 39.

[196] Procedural Order at P 80.

[197] *See* Module C, Original Sheet No. 400.

intricate nature of the FTR process and the potential need for future timeline changes.

266. We will allow GFA parties that have not currently settled on an option to choose between Options A and C, or they may convert their agreements to service under the TEMT prior to commencement of FTR nominations.[198]

267. This decision honors GFA contracts by preserving an option that maintains the principle of financial indifference through exemptions from congestion costs and any marginal loss charges above the system average, and has the added benefit of incorporating more GFAs into the Midwest ISO markets. We agree with intervenors that greater GFA participation brings greater market benefits. We also acknowledge that the use of Option B does cause uplift for all non-Option B parties. However, the extent of that uplift is mitigated by the limited amount of MW and limited number of parties that chose Option B by July 28, 2004 as discussed in the Findings of Fact.[199] Furthermore, this decision strikes the appropriate balance between encouraging GFA settlements and minimizing the potential for uplift by limiting the availability of Option B to parties that voluntarily and timely settled. In drawing this conclusion we note Dr. Hogan's testimony where he states, "Option B could undermine the incentive and efficient scheduling properties of the LMP-based Tariff, so I agree that this approach should be offered only for a defined transition period."[200]

268. We will allow the Option B treatment to continue for parties that settled prior to July 28, 2004 until February 1, 2008. In this regard, we accept the provision that the Midwest ISO will evaluate the impact that the optional treatments for GFAs have

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[198] We note that the Midwest ISO has recently proposed to conduct their tier I FTR nominations between October 22, 2004 and October 29, 2004 in lieu of the original October 1 start date.

[199] All of the settling GFAs that may elect Option B at any one time represent approximately 7,000 MW or 6.5 percent of the Midwest ISO's 2004 peak load of 107,552 MW. Of those, GFAs representing approximately 5,500 MW, or 5 percent of the Midwest ISO's total peak load, elected Option B for their initial treatment under the TEMT. Further detail on Option B settlements is provided in the GFA settlements section of this order.

[200] *See* Hogan testimony at 54.

24 months prior to February 1, 2008, and that it will make a section 205 filing 12 months prior to February 1, 2008, that details a new proposal for the treatment of GFAs after the transition periods concludes.[201] At that time we will evaluate any proposals to extend the availability of Option B. We direct that the proposal, due on or before February 1, 2007, analyze the effect Option B treatment has had on the other Market Participants, including the amount of uplift that has been needed to cover the costs of congestion and the difference between marginal and average losses.

269. We acknowledge there is some theoretical risk of gaming opportunities under Option B, in particular if, under some circumstances, GFA parties that schedule day-ahead are then able to garner "congestion relief" payments in the real-time energy market and if there is a related phantom-congestion problem as referenced in Dr. Hogan's testimony.[202] However, our decision to grant the limited use of Option B is based on our finding that the possible financial impacts of such activities are outweighed by the benefits to the operations of the Day 2 market by incorporating the day-ahead scheduling under the Option B method. In this regard, we reiterate that the amount of energy associated with the GFAs that settled on Option B is currently less than 5 percent of the overall market and the amount of uplift associated with these contracts would be correspondingly small. We also note that the required IMM information report on GFA gaming behavior and GFA scheduling behavior under Market Behavior Rule 2, directed above, will help quantify the scope and impact of any such activities.

270. We disagree with the Midwest TO's that the Midwest ISO's Option B proposal to recover congestion revenue shortfalls through uplift charges is unreasonable.[203] Costs associated with making up for congestion revenue shortfalls are essentially incurred to maintain firm transmission service, similar to the costs of uneconomic dispatch incurred to maintain firm service. We note that the Commission has previously found that redispatch costs incurred to maintain service to network and native load customers were prudent and necessary to maintain reliability and that those costs are to be shared between network and native load under the Order No. 888 *pro forma* tariff.[204] That is, it is

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[201] *See* Module C, section 38.8.4, Original Sheet No. 454.

[202] *See* Hogan testimony at 42-45.

[203] Midwest ISO TO May Comments at 15.

[204] "Tariff sections 33.2 and 33.3 clearly establish that redispatch of all Network Resources and the transmission provider's own resources are only to be performed to maintain the reliability of the transmission system, not for economic reasons. Such costs are to be shared between network customers and the transmission provider on a load ratio basis." Order No. 888-A at 12,327.

reasonable to share the cost of redispatch to maintain firm service among all firm service customers who benefit from that redispatch. Following that principle, it is reasonable

that Option B transactions share in the cost of congestion uplift associated with maintaining their firm service rights.[205]

271. We have not adopted the Midwest ISO TOs' proposed alternative GFA treatment options. Their proposal is designed to avoid trapped costs. However, our action in this order, by only requiring GFAs subject to the just and reasonable standard of review to schedule and settle their transactions under the TEMT, already avoids trapped costs.

272. With respect to the OMS proposal to limit the Option B FTR set aside to the Tier I and Tier II limits, we decline to adopt this proposal. While we understand the concern that the option may result in fewer FTRs for non-GFAs, we do not expect the impacts to be significant or widespread in light of the level of MW committing to the option.

273. Finally, we direct the Midwest ISO to reorder its tariff to eliminate a section numbering inconsistency. Section 42.2.4, Original Sheet No. 613, should be corrected to read Section 43.2.4.

2. GFA Party Settlements

274. As stated above, in the Procedural Order, the Commission strongly encouraged GFA settlements and stated that it would be receptive to GFA parties voluntarily agreeing, in settlement, to accept one of the Midwest ISO's proposed scheduling and settlement options, including Option B, for treatment of GFA transactions, or to convert their contracts to TEMT service.[206] The Commission also stated that "such settlements avoid litigation of GFA issues and further the Commission's goals in facilitating voluntary resolution of these issues prior to the start of the Midwest ISO energy markets."[207] The Commission explained that, if it approved a settlement, it did not intend

[205] The pass through of costs under GFAs is addressed in the discussion regarding the designation of GFA Responsible Entity in the "Discussion Regarding the Briefs on Exceptions to the Presiding Judges Findings" section of this order.

[206] Procedural Order at P 80.

[207] *Id*. at P 82.

to later revisit its decision when it addressed the non-settling parties' GFAs.

275. As a result of Steps 1 and 2, GFA parties settled by mutually agreeing to accept the TEMT options for GFA treatment by choosing Option A, Option B, or a combination of A and B, or, by mutually agreeing to convert their contracts to the transmission and energy market provisions of the TEMT. Parties settled 52 contracts, representing a total of approximately 9,729 MW. In specific, 14 GFA parties chose to settle on Option A (a total of approximately 1,599 MW), including contract numbers 94-100, 188, 223, 347, 399 (which is also listed as 417), and 417-20. The 30 GFA parties choosing to settle on Option B (a total of approximately 5,247 MW) include contract numbers 34, 141, 152, 159, 182, 214, 285, 342, 343, 355, 357-59, 362, 363, 372, 373, 378, 392, 406, 412-14, 426, 441-45, and 449. The 3 GFA parties choosing a combination of Options A and B (396 MW) include contract numbers 142, 144, and 346. Finally, 5 GFA parties chose to convert their contracts to TEMT service, including contract numbers 216, 224, 324, 375, and 376 (representing 2,487 MW).

(a) <u>Settlement Comments</u>

276. On July 16, 2004, Cinergy filed comments contesting provisions of certain settlements that purported to adopt Option B treatment or reserved the right to select Option B.[208] Specifically, Cinergy states that Option B is unjust, unreasonable, and unduly discriminatory and that settlements adopting Option B are unlawful and can not be accepted.[209] It asserts that the Commission should not adopt Option B settlements, absent a ruling on its lawfulness. Cinergy states that the Commission should either require, as a condition for accepting the additional elements submitted in Option B settlements, that the parties strike their election of Option B, or delay ruling on the Option B settlements pending resolution of the legality of Option B. Moreover, Cinergy asserts that the lesser "fair and reasonable" standard that the Commission appeared to invoke with respect to Option B is applicable only to uncontested settlements and that for contested settlements, the standard is just, reasonable, and not unduly discriminatory, which must be supported by substantial evidence.

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[208] Cinergy lists contract numbers 101-12, 182, 209, 210, 212, 214, 222, 256, 257, 266, 285, 289, 297, 308, 323, 343, 356-59, 362, 363, 389-91, 406, 413, 414, 441-43, 448, and 449, as either selecting Option B or reserving the right to select Option B.

[209] Cinergy notes that it is a party to various settlement agreements in which the parties have selected Option B, but that it does not comment on its settlements because, in each, Cinergy reserved the right to challenge the lawfulness of Option B.

277. Cinergy contends that permitting parties to select Option B leads to inefficiency and reduced reliability in the market in addition to unfair cost shifting and undue discrimination. Cinergy emphasizes that Option B will result in market inefficiency because, with load tied up in GFAs, Option B would distort the TEMT energy and FTR markets and undermine the LMP-based, financial transmission rights paradigm. It also stresses that Option B gives GFA parties discounts on losses, charging them the marginal cost of losses day-ahead, but then rebating the difference between their marginal and average costs, resulting in less efficient grid use and fewer incentives to invest in generation and transmission upgrades. Cinergy argues that Option B would also promote over-scheduling, which creates phantom congestion, as it allows GFA customers to schedule their full load entitlement in the day-ahead market whenever real-time congestion is anticipated. It explains that, regardless of the amount of transmission the GFA customer actually used in real-time, the GFA customer would still receive a full rebate for all of the transmission scheduled day-ahead, including the unused portion.

278. Cinergy also emphasizes that, contrary to Dr. Hogan's assumption, there is no Commission-imposed constraint to make GFA parties "financially indifferent, or *better*" to the GFA proposal.[210] It states that the Commission only required preservation of material benefits and obligations under the contract. Thus, Cinergy argues that allowing financial indifference to LMP, as Option B does, preserves more than the material benefits under a GFA because it grants GFA parties all of the benefits of a new market design and excuses them from all price signals while shifting costs to non-GFA loads. Cinergy also asserts that, contrary to Dr. Hogan's assertions, virtual bidding, while a good idea, cannot cure the flaws of Option B. Cinergy argues that Options A and C are better alternatives than Option B because Options A and C integrate the GFAs into the scheduling and settlement process and do not materially alter the rights of GFA parties. Thus, it states that Options A and C are neither inefficient nor unduly discriminatory.

279. Finally, Cinergy requests that the Commission not yet approve the settlement offer for GFA 343. It states that GFA 343 identifies the "Cinergy Hub," which is not an appropriate OASIS designation, as a source point, but does not provide for any transmission on the Cinergy system. Cinergy explains that, for such a "partial path" GFA, it is unclear how FTRs and congestion costs will be allocated between transmission taken on an open access basis, and that taken under the GFA. Instead, it states that the Commission should require submission of data sufficient to permit clear and unambiguous application of the Midwest ISO rules.

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[210] Cinergy settlement comments at 13; Exh. MISO-5 at 48 (Hogan).

(b) Commission Discussion

280. Consistent with the discussion above, as well as the Commission's goals in facilitating and encouraging voluntary resolution of the GFA issue prior to the start of the Midwest ISO Energy Markets, we will accept all of the GFA settlements listed above, including those of parties who chose Option B.[211] We received a number of joint filings that expressed, per the Procedural Order's instructions, GFA parties' willingness to settle on one of the Midwest ISO's proposed scheduling and settlement options.[212] We interpret these settlement filings to incorporate the material terms and conditions of the TEMT, particularly section 38.8.3 thereof, and we find that these settlements are just and reasonable.

281. With respect to GFA Nos. 142 and 144, relating to service from PSI Energy, Inc. (a franchised public utility affiliate of Cinergy) to Wabash Valley Power Association, Inc., the GFA parties indicate that they select Option A treatment for certain transactions (representing 70 MW) and Option B for other transactions (representing 326 MW). However, it is unclear whether the transactions for each option are associated with one GFA, or whether the parties have selected different options for separate transactions under the same GFA. The TEMT requires that parties to a GFA select just one option for treatment of the GFA.[213] Accordingly, we will approve the settlement for GFA Nos. 142 and 144, but will require the parties to choose one option for the transactions under each GFA and notify the Midwest ISO of their selection, in accordance with the TEMT, before the commencement of FTR nominations.

282. With respect to Cinergy's argument that permitting parties to settle on Option B results in unfair cost shifting and undue discrimination, we reiterate our discussion above that the amount of energy associated with the 29 GFAs that settled on Option B is currently less than 5 percent of the overall market and the amount of uplift associated with these contracts would be correspondingly small. We also note that, initially, Option B puts settling parties (former GFAs) on the same footing as non-GFAs for purposes of scheduling and the requirement to pay for imbalances in the real-time LMP market. To

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[211] *See* Procedural Order at P 80.

[212] *See id.* at P 69 (requiring parties to "make a simple statement in their joint filings to indicate whether or not they are willing to voluntarily convert their contract to TEMT service or settle their GFA by voluntarily accepting the Midwest ISO's treatment of GFAs.").

[213] *See* Module C, section 38.8.3, Original Sheet No. 445.

ensure financial indifference, settling parties are provided protections from congestion costs. In other words, Option B eliminates scheduling preferences as a cost of uplift for congestion costs that are shared by these same parties and non-GFAs. Allocation of a share of the uplift to non-GFAs is justified since they benefit from the elimination of scheduling preferences. In this context of shared costs, and recognizing the elimination of scheduling preferences, we do not consider the cost burden associated with Option B to be unduly discriminatory.

E. Schedules 16 and 17

1. The Midwest ISO's Proposal

283. In Docket No. ER02-2595-000 the Midwest ISO proposed Schedule 16, Financial Transmission Rights Administrative Service Cost Recovery Adder (FTR Service) and Schedule 17, Energy Market Support Administrative Service Cost Recovery Adder (Energy Market Service) as mechanisms to recover from Transmission Customers, Transmission Owners and Users the costs associated with implementing and administering the FTR markets and energy markets. Among other things, the Commission accepted the proposal and set for a paper hearing the cost allocation and rate design reflected in the proposed charges in Schedules 16 and 17.

284. In the March 31 TEMT filing in this proceeding, the Midwest ISO states that the Commission's decision in the paper hearing in Docket No. ER02-2595-000 will be incorporated into the TEMT. In this proceeding the Midwest ISO proposes modifications to the Schedules 16 and 17 that were originally proposed in Docket No. ER02-2595-000. The Midwest ISO proposes to assess Market Participants the charges in Schedules 16 and 17, instead of the Transmission Customers, Transmission Owners and Users as initially proposed. Moreover, the Midwest ISO proposes other minor modifications to Schedules 16 and 17, clarifying definitions in the formulary rates and conforming the schedules to the recently filed TEMT.

285. In the March 31 Filing, the Midwest ISO proposes three options for treating GFAs from which the parties to the GFAs may select, as discussed above. The Midwest ISO states that to the extent that the Commission applies Schedule 16 and 17 charges to GFA transactions under any of the three options, the Midwest ISO supports allowing the Market Participant assessed those charges for transactions under the GFA to recover those costs in its rates.

2. Comments

286. OMS states that assigning costs on a cost-causative basis is an important concept that should be considered on an on-going basis and is essential to ensuring an efficient

market.

287. The Nebraska Intervenors, non-jurisdictional vertically integrated utilities, are concerned that the Midwest ISO's market design will force them to pay the Schedule 16 and 17 charges. The Nebraska Intervenors argue that as an entity that would largely self-schedule its resources, the Schedule 16 and 17 charges outweigh the benefits, if any, of joining the Midwest ISO.

288. Midwest ISO TOs and Basin, *et al*. state that GFA parties should not have to pay Schedule 16 and 17 charges for their GFA transactions. Multiple TDUs state that parties to GFAs that choose Option B, should not be assessed Schedule 16 costs because they will not hold FTRs. Additionally, Manitoba Hydro states that assessing Schedule 16 costs to its GFAs will undermine the economic assumptions that formed the parties' basis for committing to the agreements. If the Commission only has jurisdiction over portions of certain existing agreements, Manitoba Hydro questions how the Commission can modify portions of these agreements without altering the non-jurisdictional aspects of the agreement or undoing the bargain as a whole. Manitoba Hydro requests that the Commission clarify that Schedule 16 and 17 charges do not apply to any existing agreements involving non-jurisdictional entities to the extent that such agreements relate to energy generated in Canada and exported by Manitoba Hydro to purchasers within the U.S.

289. First Energy, on the other hand, supports the assessment of the costs of the Energy Markets to GFAs to avoid subsidization of the GFAs by non-GFA parties. FirstEnergy suggests authorizing a limited filing by the Transmission Owners for an increase in transmission rates to cover the energy market costs under the tariff.

290. Crescent Moon also states that Schedule 17 should be unbundled to avoid cross-subsidization. Specifically, Crescent Moon states that transmission-related scheduling and spot market-related costs should be unbundled and assessed to those causing those costs.[214] Crescent Moon also states that the Midwest ISO markets should stand on their own in terms of cost recovery. If a market activity fails to recover its administrative costs, it sends an important price signal to the Midwest ISO that it should restructure the offering to make it less expensive to achieve financial breakeven. To the extent that the Commission decides that GFA transactions should be subject to Schedule 16 and 17 charges, Crescent Moon states that Schedule 16 and 17 charges should be applied to GFA

[214] For example, Crescent Moon contends that self-scheduling entities and parties engaged in bilateral transactions should not be liable for spot market-related costs arguing that such parties do not benefit from those activities.

parties consistent with the parties' responsibilities under the GFA. AMP-Ohio states that the billing determinants for the Schedule 17 charge should be modified to include a per-bid charge to ensure that the Midwest ISO's systems are not overworked due to a high volume of bids and offers submitted by virtual traders. AMP-Ohio notes that virtual traders have stressed the systems of PJM.

291. Detroit Edison states that its pumped storage facility is flexibly operated to alternate between pumping and generation in ways that produce optimal reliability and economic benefits. Detroit Edison contends that by imposing Schedule 17 charges on pumped storage facilities, these units could be double charged for Schedule 17 service (*i.e*., charged for injections and withdrawals for pumping and generation).

292. Cinergy states that utilities need assurance that they will be able to recover the costs incurred under Schedules 16 and 17, particularly costs associated with service to retail customers. Many utilities operate under retail rate freezes and may be subject to trapped costs if they are not provided an alternative method to recover the costs of the Energy Markets from their customers.

3. Commission Discussion

293. The Commission agrees with OMS that cost causation is important in allocating costs and should be considered on an on-going basis. As the Commission states in the companion order in Docket No. ER02-2595-000, *et al*., the Midwest ISO took an important initial step in unbundling market costs from its Schedule 10 ISO Cost Adder by proposing separate charges in Schedules 16 and 17 to recover costs associated with implementing FTR Service and Energy Market Service.[215] While such unbundling by the Midwest ISO will help align cost responsibility with the benefits received, the Commission recognizes that further refinement of the unbundling of the Schedule 16 and 17 charges may be appropriate after the Midwest ISO obtains operational experience.

(a) Schedule 16

294. The Commission explains in the order issued concurrently with this order, in Docket No. ER02-2595-000, that all FTR-holders benefit from FTR Service and should pay the Schedule 16 charge for the benefits provided by the FTRs. The Commission finds that GFAs choosing either Option A or Option B benefit from the FTR Service provided by the Midwest ISO for the same reasons the Commission relies upon finding

[215] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,235 (2004) (Schedule16/17 Order).

that FTR-holding bilateral transactions and self-scheduling transactions benefit from FTR Service in Docket No. ER02-2595-000. These GFAs are subject to congestion costs and the FTRs act as a hedge against those congestion costs.[216] Regardless of who actually holds the FTRs, the Option A and Option B GFAs benefit from the hedge provided by the FTRs and these GFAs should be assessed the Schedule 16 charge for that benefit.[217] The Commission believes that, as Option B simply provides an alternative hedging mechanism to holding FTRs for GFAs that are subject to the Midwest ISO Energy Markets, there should be no distinction between Option A GFAs and Option B GFAs for Schedule 16 treatment.

295. The Commission finds that carved-out GFAs should not be assessed the Schedule 16 charge. The carved out GFAs have retained their physical transmission rights and are not subject to congestion costs in the first instance. Since the carved out GFAs are not subject to congestion costs in the Midwest ISO Energy Markets, they have no need for FTRs as a hedge against congestion costs; therefore, these GFAs do not benefit from the FTR Service as the Option A and Option B GFAs do nor do these GFAs benefit like the FTR-holding, bilateral transactions and self-scheduling transactions.

296. Since Detroit Edison’s GFA involving the Ludington, MI pumped storage unit is a carved out GFA, it is not subject to the Schedule 16 charge. Likewise, since Manitoba Hydro’s sales into the United States are being carved out, as discussed above, Manitoba Hydro’s sales are exempt from the Schedule 16 charge.

(b) <u>Schedule 17</u>

297. In the companion order in Docket No. ER02-2595-000, the Commission also finds that entities engaged in self-scheduling transactions and bilateral transactions should pay the Schedule 17 charge because they benefit through their use of the transmission grid which is made more reliable as a result of the security-constrained economic dispatch that the Midwest ISO will operate in its Energy Markets. In addition the markets reveal the value of congestion so that efficient means of eliminating congestion can be implemented, thereby, increasing the efficiency of the grid. In that order, the

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[216] GFAs that choose Option A hold the FTRs and GFAs that choose Option B have the Midwest ISO hold the FTRs for them.

[217] By contrast, Option C GFAs do not receive a FTR as a hedge. These GFAs should not be assessed the Schedule 16 because they don’t receive the benefit that Option A and Option B GFAs receive.

Commission also explains that the bilateral transactions and self-scheduling transactions benefit from the existence of the Energy Markets and should therefore pay the costs to establish the Energy Markets. These transactions benefit from the efficient and transparent prices resulting from the Energy Markets and the ability to use the spot markets whenever it is economic to do so. But the Commission added that even though parties to bilateral transactions and self-scheduling transactions may not be using the spot market in any given hour, they benefit from, and therefore should pay for having, an energy market.[218]

298. With respect to Energy Market Service, the Commission finds that all GFA transactions should be assessed the charge for Energy Market Service in Schedule 17 regardless of whether or not they are carved out of the Midwest ISO Energy Markets. GFAs will receive the same benefits, discussed in the Commission's companion order in Docket No. ER02-2595-000, as the bilateral transactions and self-scheduling transactions from the Energy Market Service. As the courts have ruled, "upgrades designed to 'preserve the grid's reliability' constitute 'system enhancements [that] are presumed to benefit the entire system.'"[219] Similar principles apply to the cost of implementing the Energy Markets, which will produce more reliable service and more efficient Energy Markets that will benefit all transacting over the Midwest ISO grid. GFAs should pay for the benefits they receive. Likewise, non-GFA transactions should not subsidize GFA transactions.

299. The Commission agrees with Detroit Edison and concludes that Detroit Edison should be assessed the Schedule 17 charge only on its pumped storage facility's injections into the transmission system.[220] Since the extractions from the transmission system occurring when the facility is in pumping mode, are not to serve load in the

[218] Schedule 16/17 Order at P 47 (*citing* Midwest ISO Transmission Owners, *et al*. v. FERC, 373 F.3d 1361, 1371 (D.C. Cir. 2004).

[219] *See* Entergy Services, Inc., 319 F.3d 536, 543 (D.C. Cir. 2003) (*citing* Western Massachusetts Electric Co. v. FERC, 165 F.3d 922, 923, 927 (D.C. Cir. 1999)).

[220] A pumped storage project is designed to meet the system's need for electricity during periods of peak demand. Such a project operates by means of two reservoirs at different elevations in close proximity to one another. During times of low energy demand other generation is used to pump water from the lower reservoir to the upper reservoir. At times of peak demand, the water is dropped back to the lower reservoir, through generating facilities, to produce power.

traditional sense,[221] such extractions from the transmission system should not be assessed the charge. By charging the pumped storage facility only when it is in generation mode, the pumped storage facility will be placed on the same footing as other generation. The Commission also finds that Manitoba Hydro's sales into the United States should be subject to the Schedule 17 charge just as the other GFAs, including other carved-out GFAs, are subject to the Schedule 17 charge, because they will benefit from the Energy Markets in a manner similar to any other power sales transaction.

(c) <u>Billing Entity</u>

300. In this proceeding the Midwest ISO has proposed to bill Market Participants the Schedule 16 and 17 charges instead of "Transmission Customers, Transmission Owners, Users or other entities," as originally proposed. The Commission accepts the change, to clarify which entities will be charged for Schedule 16 and 17 service, subject to further modification. Midwest ISO should modify Schedules 16 and 17 to clarify their applicability to GFA transactions consistent with our findings above and to clarify that the billing entity for GFAs subject to Options A, B or C, either pursuant to settlements or the requirements of this order, is the GFA Responsible Entity. These revisions should also reflect that the GFA Responsible Entity for GFAs subject to Option B treatment will be responsible for Schedule 16 charges for the hedge in the Day-Ahead Energy Market provided in that option. Finally, consistent Opinion Nos. 453 and 453-A, which require that the Transmission Owner or ITC Participant take transmission service under the Midwest ISO Tariff in order to satisfy its obligations under the GFA,[222] the billing entity for carved out GFAs is the Transmission Owner or ITC Participant taking transmission service pursuant to the Midwest ISO tariff to meet its obligations under the GFA.

301. The Commission has already addressed FirstEnergy and Cinergy's concerns about cost recovery from GFAs and retail load in previous orders.[223] The Commission stated

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[221] *See* Power Authority of the State of New York, 25 FERC ¶ 61,084 at 61,265 (1983) (pumped storage is an energy storage device which takes unused off-peak energy, and stores it for peak energy use). *See also* Norton Energy Storage, L.L.C., 95 FERC ¶ 61,476 (2001) (Commission views the pumping energy not as being consumed, but rather as being converted and stored).

[222] Opinion No. 453 at 61,173.

[223] *See* Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,279 (2003), *order denying rehearing*, 106 FERC ¶ 61,337 (2004).

that it was speculative whether states with retail rate freezes will block the recovery of any Commission-established rates, and even if states did deny recovery of Commission-established rates, any such denial would be challengeable in state fora.[224] The Commission reiterated that utilities have the opportunity to make a filing that demonstrates and supports that such costs are currently unrecoverable and should be treated as a regulatory asset. Additionally, the Commission denied a request to generically modify GFAs because the request was based solely on the statement that there were many contracts precluding modification through unilateral filings to recover Schedule 16 and 17 charges. The Commission also stated 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.[225]

302. 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.

F. Attachment P - Docket No. ER04-106-002

303. On May 26, 2004, the Midwest ISO submitted a compliance filing containing proposed revisions to Attachment P as directed by the Commission in its underlying order.[226] As is evident from our discussion above, the Midwest ISO's compliance filing has been overtaken by events, and so we will direct that the Midwest ISO make a new compliance filing.

304. Specifically, with respect to which grandfathered agreements should be included in Attachment P, the Commission concludes that the definition of GFAs provided in the TEMT should be utilized for determining which GFAs should be included in Attachment P. That definition, section 1.126 of the recently approved TEMT, defines GFAs as:

> An agreement or agreements executed or committed to prior to

[224] Midwest Independent Transmission System Operator, Inc., 106 FERC ¶ 61,337 at P 14.

[225] *Id*. at P 18 (*citing* Opinion No. 463 at P 46).

[226] *See* Midwest Independent Transmission System Operator, Inc., 106 FERC ¶ 61,387 (2004).

> September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the commission's policies. These agreements are set forth in Attachment P to this Tariff.

Thus, the Commission directs the Midwest ISO to make a compliance filing, in a new subdocket of Docket No. ER04-106, revising Attachment P.

305. Given the Commission's finding here, that the section 1.126 definition contained in the TEMT should be used to determine which agreements should be included in Attachment P, this compliance filing should not reflect any other criteria for determining whether an agreement should be included, or excluded, from Attachment P.[227] We also direct the Midwest ISO to specify for each contract listed in Attachment P the contract's treatment per the directives of this order, (*i.e.*, either converted to TEMT service or subject to a choice among Options A, B, or C pursuant to a settlement of GFA treatment approved in this order, subject to a choice among Option A or Option C because the GFA is subject to the just and reasonable standard of review, subject to a carve-out from the Midwest ISO Markets, or excluded from this proceeding).

<u>The Commission orders</u>:

(A) Transmission Owners and ITC Participants providing service under GFAs that did not settle and that are subject to a just and reasonable standard of review must choose scheduling and settlement Option A or Option C, and notify the Midwest ISO of their selection before October 1, 2004, in accordance with the TEMT, as discussed in the body of this order.

(B) The Midwest ISO is directed to carve out of its Energy Markets all other GFAs that did not settle, as described in the body of this order.

(C) The Midwest ISO's proposed Option A and Option C TEMT treatment for GFAs are hereby accepted, as discussed in the body of this order.

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[227] We expect that the Midwest ISO will be adding or deleting entities, based on the TEMT definition, and correcting inaccuracies. If the protestors to the earlier compliance filings still have concerns after the filing of this new compliance filing, they can raise them in response to this new compliance filing.

(D) The Midwest ISO's proposed Option B is hereby accepted for those parties that chose it prior to July 28, 2004, as discussed in the body of this order.

(E) The 52 settlements described above are hereby accepted, as described in the body of this order.

(F) The parties to GFA Nos. 142 and 144 are directed to choose between Option A and Option B for the transactions under each GFA and notify the Midwest ISO of their selection, in accordance with the TEMT, before the commencement of FTR nominations, as discussed in the body of this order.

(G) Parties to GFAs are directed to provide the Midwest ISO with more detailed information regarding the capacity between nodes to be reserved for the GFAs, and data regarding historical capacity used on a seasonal basis, as described in the body of this order

(H) The Midwest ISO is hereby directed to file reports with the Commission, as described in the body of this order.

(I) The Midwest ISO is hereby directed to make compliance filings, in Docket Nos. ER04-691-000 and ER04-104-000, within 30 and 60 days of the date of this order, as discussed in the body of this order.

(J) The Midwest ISO is hereby directed to make a compliance filing, in Docket No. ER04-106, within 60 days of the date of this order, providing a revised Attachment P consistent with the definition of grandfathered agreements in the TEMT, as discussed in the body of this order.

(K) The IMM is hereby directed to monitor GFA customers for gaming behavior and provide an informational report to the Commission prior to the second FTR allocation, as discussed in the body of this order.

(L) The presiding judges' Findings of Fact are hereby affirmed in part and reversed in part, to the extent discussed in the body of this order.

(M) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a further public hearing shall be held concerning GFA Nos. 273, 284, 297, 306, 309, 311, 313, 314, 316, 317, and 450. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Paragraphs (N) and (O) below.

(N) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2004), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in these proceedings within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge in writing or by telephone within five (5) days of the date of this order.

(O) Within sixty (60) days of the date of this order, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(P) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Linda Mitry,
Acting Secretary.

Appendix A

Relevant Parties Filing Protests or Comments to the Midwest ISO's March 31 Filing

Alliant – Alliant Energy Corporate Services, Inc.
ATCLLC – American Transmission Company LLC
Basin, *et al.* – Basin Electric Power Cooperative, East River Electric Power Cooperative, Inc., Central Power Electric Cooperative, Inc. and Capital Electric Cooperative, Inc.
Cinergy – Cinergy Services, Inc.
Consumers – Consumers Energy Company
Crescent Moon Utilities – Basin Electric Power Cooperative, Heartland Consumers Power District, Minnkota Power Cooperative, Inc., NorthWestern Energy, Sunflower Electric Power Corporation and the Upper Great Plains Region of the Western Area Power Administration
Dairyland – Dairyland Power Cooperative
Detroit Edison – Detroit Edison Company
EPSA – Electric Power Supply Association
FirstEnergy – FirstEnergy Service Company
Midwest ISO TOs – Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, and Central Illinois Light Co. d/b/a AmerenCilco; Aquila, Inc. d/b/a Aquila Networks (f/k/a Utilicorp United, Inc.); City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; LG&E Energy Corporation (for Louisville Gas and Electric Co. and Kentucky Utilities Co.); Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company (Wisconsin), subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest TDUs – 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, Upper Peninsula Transmission Dependent Utilities and Wisconsin Public Power, Inc.
Minnkota – Minnkota Power Cooperative, Inc.
Minnesota Municipal – Minnesota Municipal Power Agency
Municipal Participants – Michigan Public Power Agency, Michigan South Central

Power Agency, Department of Municipal Services of Wyandotte, Michigan and City of Hamilton, Ohio

NRECA – National Rural Electric Cooperative Association
OMS – Organization of MISO States
Otter Tail – Otter Tail Power Company
PSEG – PSEG Energy Resources & Trade LLC
Reliant – Reliant Energy, Inc.
WPPI – Wisconsin Public Power Inc
WPS Resources – WPS Resources Corporation
WUMS Load-Serving Entities – Wisconsin Electric Power Company, Edison Sault Electric Company, Wisconsin Public Service Corporation, Upper Peninsula Power Company, Wisconsin Power and Light Company, Madison Gas and Electric Company, Wisconsin Public Power, Inc. and Manitowoc Public Utilities

<u>Parties Filing Analysis Comments Pursuant to P 72 and 73 of the Procedural Order</u>

Detroit Edison
LG&E – LG&E Energy LLC, on behalf of its utility operating companies Louisville Gas and Electric Company and Kentucky Utilities Company
Michigan/Kentucky Parties - Michigan Public Power Agency, the Michigan South Central Power Agency, the City of Wyandotte, Michigan, and the East Kentucky Power Cooperative, Inc.
Midwest ISO TOs – City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Minnesota Power (and its subsidiary Superior Water, L&P); Montana Dakota Utilities Co.; Northern States Power Company and Northern States Power Company (Wisconsin); subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest TDUs
Rural Electric Cooperatives – National Rural Electric Cooperative Association, Basin Electric Power Cooperative, Capital Electric Cooperative, Inc., Central Power Electric Cooperative, Inc., Dairyland Power Cooperative, East River Electric Power Cooperative, Inc., Hoosier Energy Rural Electric Cooperative, Inc., Great River Energy, and Minnkota Power Cooperative, Inc.

<u>Parties Filing June 25 Comments Pursuant to P 74 of the Procedural Order</u>

AECC - Arkansas Electric Cooperative Corporation
Cinergy – Cinergy Services, Inc., The Cincinnati Gas & Electric Company, PSI Energy,

Inc., and The Union Light, Heat and Power Company
Corn Belt – Corn Belt Power Cooperative
Detroit Edison
Dynegy – Dynegy Power Marketing, Inc. and Dynegy Midwest Generation, Inc.
FirstEnergy
Hoosier - Hoosier Energy Rural Electric Cooperative, Inc.
LG&E
Michigan/Kentucky Parties
Midwest ISO TOs – City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Minnesota Power (and its subsidiary Superior Water, L&P); Montana Dakota Utilities Co.; Northern States Power Company and Northern States Power Company (Wisconsin); subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest TDUs
Montana-Dakota – Montana-Dakota Utilities Company
North Dakota Commission – North Dakota Public Service Commission
OMS
Rural Electric Cooperatives – National Rural Electric Cooperative Association, American Public Power Association, Basin Electric Power Cooperative, Capital Electric Cooperative, Inc., Central Power Electric Cooperative, Inc., Dairyland Power Cooperative and East River Electric Power Cooperative, Inc.
TVA – Tennessee Valley Authority
WPPI
WPS Resources

<u>Parties Filing Reply Comments Pursuant to P 74 of the Procedural Order</u>

Cinergy
Michigan/Kentucky Parties
Rural Electric Cooperatives – National Rural Electric Cooperative Association, Basin Electric Power Cooperative, Capital Electric Cooperative, Inc., Central Power Electric Cooperative, Inc., Dairyland Power Cooperative, East River Electric Power Cooperative, Inc., Hoosier Energy Rural Electric Cooperative, Inc., Great River Energy, and Minnkota Power Cooperative, Inc.

<u>Parties Filing Briefs on Exceptions</u>

Alliant and WPS Resources
Basin, *et al.* – Basin Electric Power Cooperative, Central Power Electric Cooperative, Inc. and East River Electric Power Cooperative, Inc.
Cleveland and AMP-Ohio - The City of Cleveland, Ohio and American Municipal Power-Ohio
Dairyland
Detroit Edison
EKPC - East Kentucky Power Cooperative, Inc.
FirstEnergy
Great River – Great River Energy
LG&E
Minnesota Power
Minnkota
MMTG - Midwest Municipal Transmission Group
Montana-Dakota
Northwestern - Northwestern Wisconsin Electric Company
Otter Tail
Rural Electric Cooperatives – National Rural Electric Cooperative Association, Associated Electric Cooperative, Inc., Central Iowa Power Cooperative, Inc., Corn Belt Power Cooperative, Dairyland Power Cooperative, Minnkota Power Cooperative, Inc., and Southern Illinois Power Cooperative
Xcel – Xcel Energy Services Inc.

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
2	Carve Out	0.80		Alliant Energy - IPL	N/A	N/A
3	Carve Out	7.00		Alliant Energy - IPL	N/A	N/A
4	Carve Out	1.50		Alliant Energy - IPL	N/A	N/A
5	Carve Out	0.50		Alliant Energy - IPL	N/A	N/A
6	Carve Out	3.00		Alliant Energy - IPL	N/A	N/A
7	Carve Out	0.60		Alliant Energy - IPL	N/A	N/A
8	Carve Out	0.75		Alliant Energy - IPL	N/A	N/A
9	Carve Out	0.15		Alliant Energy - IPL	N/A	N/A
11	Carve Out	3.20		Alliant Energy - IPL	N/A	N/A
12	Carve Out	144.00	We note that Great River and Alliant report that they have entered into a letter of intent to terminate contract by 3/1/05.	Alliant Energy - IPL	N/A	N/A
14	Carve Out	12.90	Maximum MW is total of largest historical capacity for each source-sink pair	Alliant Energy - IPL	N/A	N/A
16	Carve Out	591.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
17	Carve Out	24.07		Alliant Energy - IPL	N/A	N/A
19	Carve Out	37.00		Alliant Energy - IPL	N/A	N/A
20	Carve Out	0.00	GFA Nos. 20 & 41 are two separate contracts that establish one service; Maximum Cumulative MW for both reported in GFA No. 41	Alliant Energy - IPL	N/A	N/A
28	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
29	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
30	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
31	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
34	Option B	97.53		Alliant Energy - IPL	Southern Minnesota Muni Pwr Agency	Southern Minnesota Muni Pwr Agency
35	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
36	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
39	Carve Out	5.00		Alliant Energy - IPL	N/A	N/A
41	Carve Out	44.20	GFA Nos. 20 & 41 are two separate contracts that establish one service; Maximum Cumulative MW for both reported in GFA No. 41	Alliant Energy - IPL	N/A	N/A
94	Option A	75.40		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
95	Option A	3.00		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
96	Option A	4.90	Maximum MW is largest capacity of the historical data provided	American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
97	Option A	0.90		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
98	Option A	4.60		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
100	Option A	43.00		American Tx Co. - Edison Sault	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
101	Carve Out	5.20		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
102	Carve Out	4.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
103	Carve Out	7.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
104	Carve Out	4.50		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
105	Carve Out	4.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
106	Carve Out	5.40		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
107	Carve Out	5.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
108	J & R	0.50		American Tx Co. - WPS	Wisconsin Public Service Corp	Wisconsin Public Service Corp
109	J & R	1.40		American Tx Co. - WPS	Wisconsin Public Service Corp	Wisconsin Public Service Corp
110	J & R	0.70		American Tx Co. - WPS	Wisconsin Public Service Corp	Wisconsin Public Service Corp
111	Carve Out	70.00		American Tx Co. - WPS	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
112	Carve Out	20.90		American Tx Co. - WPS	N/A	N/A
141	Option B	72.00	GFA Nos. 141, 182, and 342 are all the same contract; Maximum MW for GFA No. 141 covers power transmitted from PSI to Hoosier	Cinergy - PSI		
142	Option A/B	0.00	GFA Nos. 142 and 144 are related; Maximum Cumulative MW for GFA Nos. 142 and 144 are reported under GFA No. 144.	Cinergy - PSI	Cinergy Services	Cinergy Services
144	Option A/B	396.00	GFA Nos. 144, 188 and 347 are all same the contract; GFA No. 144 Maximum MW covers service to Wabash and also includes service under GFA No. 142.	Cinergy - PSI	Wabash Valley Pwr Association	Wabash Valley Pwr Association
145	J & R	64.00		Cinergy - PSI	PSI	PSI
146	J & R	130.00		Cinergy - PSI	PSI	PSI
147	J & R	38.00		Cinergy - PSI	PSI	PSI
152	Option B	203.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	Cinergy - Cincinnati G&E	Cincinnati Gas & Electric Co	Cinergy Services
159	Option B	60.00		Cinergy - Union Light, Heat & Pwr	Cincinnati Gas & Electric Co	East Kentucky Pwr Coop
161	Carve Out	1101.00	Maximum MW covers GFA Nos. 161 - 177	Hoosier	N/A	N/A
162	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
163	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
164	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
165	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
166	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
167	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
168	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
169	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
170	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
171	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
172	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
173	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
174	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
175	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
176	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
177	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
178	Carve Out	2.00		Hoosier	N/A	N/A
179	Carve Out	400.00		Hoosier	N/A	N/A
182	Option B	7.00	GFA Nos. 141, 182, and 342 are all the same contract; GFA No. 182 Maximum MW covers power transmitted from SIGECO to Hoosier.	Hoosier	Hoosier	Hoosier
183	Carve Out	0.00	Hoosier & SIGECO indicate PSI provides service that it reports in another GFA.	Hoosier	N/A	N/A
185	Carve Out	232.00	Maximum MW is largest capacity listed in the historical data provided	Hoosier	N/A	N/A
186	Carve Out	40.00		Hoosier	N/A	N/A
188	Option A	595.52	GFA Nos. 144, 188 and 347 are all the same contract; GFA No. 188 maximum MW covers service to IMPA	Indiana Municipal Power Agency	Cinergy Services	Cinergy Services
189	Carve Out	0.00	Service provided under GFA No. 189 reported in GFA No. 188 maximum MW	Indiana Municipal Power Agency	N/A	N/A
190	Carve Out	0.00	Service provided under GFA No. 190 reported in the maximum cumulative MW for GFA No. 188	Indiana Municipal Power Agency	N/A	N/A
192	J & R	0.00	GFA Nos. 192 and 214 are the same contract	Indiana Municipal Power Agency	Indiana Muni Pwr Agency	LG&E
200	Carve Out	13.00		Indianapolis Power & Light	N/A	N/A
205	Carve Out	1872.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	International Transmission Co	N/A	N/A
206	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	International Transmission Co	N/A	N/A
207	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	International Transmission Co	N/A	N/A
209	Carve Out	234.49	MW listed for GFA No. 209 covers service under GFA No. 210	International Transmission Co	N/A	N/A
210	Carve Out	0.00	MW listed for GFA No. 209 covers service under GFA No. 210	International Transmission Co	N/A	N/A
211	Carve Out	5.90		International Transmission Co	N/A	N/A
212	Carve Out	37.13	Maximum MW is largest capacity listed in historical data presented for interchange service	International Transmission Co	N/A	N/A
213	Carve Out	85.00	We note that submittal indicated that service under this GFA is part of Detroit Edison's network load and conversion will be addressed in same manner as all other network load.	International Transmission Co	N/A	N/A
214	Option B	66.00		LG&E Energy - LG&E	Indiana Muni Pwr Agency	LG&E

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
215	J & R	113.00		LG&E Energy - LG&E	LG&E	LG&E
216	Convert to TEMT	158.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract.	LG&E Energy - LG&E	N/A	N/A
219	J & R	0.00	Parties state that no firm transmission currently taken under contract	LG&E Energy - KU	TVA	TVA
220	Carve Out	414.00	Maximum MW is largest capacity listed in historical data. MW listed are baseload and should be carved out.	LG&E Energy - KU	N/A	N/A
221	J & R	143.00	Maximum MW is largest capacity listed in historical data provided	LG&E Energy - KU	LG&E	LG&E
222	Carve Out	1014.00	GFA Nos. 222 and 406 are the same contract; GFA No. 448 is a companion; Maximum Cumulative MW for all three is listed in GFA No. 222.	LG&E Energy - KU	N/A	N/A
223	Option A	333.00	Maximum MW does not include service from customer because customer is not a Midwest ISO transmission owner.	LG&E Energy - KU	LG&E	LG&E
224	Convert to TEMT	56.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	LG&E Energy - KU	N/A	N/A
225	J & R	72.00		LG&E Energy - KU	TVA	TVA
254	Carve Out	15.50		METC	N/A	N/A
255	Carve Out	105.00		METC	N/A	N/A
256	Carve Out	39.36	Related to GFA No. 422; Maximum Cumulative MW reported in GFA No. 256	METC	N/A	N/A
257	Carve Out	232.14	Related to GFA No. 421; Maximum Cumulative MW reported in GFA No. 257	METC	N/A	N/A
266	Carve Out	90.00		METC	N/A	N/A
267	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	METC	N/A	N/A
268	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	METC	N/A	N/A
269	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	METC	N/A	N/A
273	Carve Out until hearing resolved	182.70	GFA Nos. 273 and 311 are the same contract. maximum MW reported was 710, but that is MPC's total load. Subtracted value of GFA Nos. 309 and 317. 136.7 MW = share of Coyote plant; Service to NWPS = 46 MW;	Montana-Dakota Utilities	N/A	N/A
274	Carve Out	115.70	GFA Nos. 274 and 320 are the same contract; maximum MW is NWPS load only; OTP and MDU report load as network load under the Midwest ISO OATT;	Montana-Dakota Utilities	N/A	N/A
284	Carve Out until hearing resolved	220.00	GFA Nos. 285 and 425 are related; maximum MW reported in GFA No. 284	Minnesota Power	N/A	N/A
285	Option B	108.00		Minnesota Power	Wisconsin Public Pwr Inc	Wisconsin Public Pwr Inc
286	Carve Out	43.00		Minnesota Power	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
289	Carve Out	16.00	Maximum MW includes two services reported - 12 MW and 4 MW	Minnesota Power	N/A	N/A
291	Carve Out	85.00	Maximum MW for SWL+P loads are aggregated with several other municipalities and are reported GFA No. 291. Maximum MW represents highest of range for the sink Mp.muni.swlp	Minnesota Power	N/A	N/A
293	Carve Out	2.66	Service provided by DPC to NWEC does not use Midwest ISO facilities, so not included in maximum MW	Northwestern Wisconsin Elec	N/A	N/A
297	Carve Out until hearing	150.00		Otter Tail Power Company	N/A	N/A
300	J & R	1.16	reported as 1,160 KW	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Power
302	J & R	0.23	reported as 230 KW	Otter Tail Power Company	Otter Tail Power	Otter Tail Power
304	J & R	0.57		Otter Tail Power Company	Otter Tail Power	Otter Tail Power
306	Carve Out until hearing resolved	152.00	Maximum MW includes only GRE's load of 152 MWs because OTP load of 110 MWs already included in OTP network load under Midwest ISO OATT	Otter Tail Power Company	N/A	N/A
308	Carve Out	16.20		Otter Tail Power Company	N/A	N/A
309	Carve Out until hearing resolved	331.90	Maximum MW reported was 710, but that is MPC's total load. Subtracted value of GFA Nos. 273 and 317.	Otter Tail Power Company	N/A	N/A
311	Carve Out until hearing resolved	0.00	GFA No. 273 and 311 are the same contract. Maximum MW reported was 710, but that is MPC's total load. Subtracted value of GFA Nos. 309 and 317. 136.7 MW = share of Coyote plant; Service to NWPS = 46 MW;	Otter Tail Power Company	N/A	N/A
313	Carve Out until hearing resolved	0.00	Maximum MW already included in GFA Nos. 273, 309 and 317	Otter Tail Power Company	N/A	N/A
314	Carve Out until hearing resolved	0.00	Maximum MW already included in GFA Nos. 273, 309 and 317	Otter Tail Power Company	N/A	N/A
316	Carve Out until hearing resolved	0.00	Maximum MW already included in GFA Nos. 273, 309 and 317	Otter Tail Power Company	N/A	N/A
317	Carve Out until hearing resolved	250.00	Maximum MW reported as 710, but subtracted value of GFA Nos. 273 and 309.	Otter Tail Power Company	N/A	N/A
318	J & R	130.00	Maximum MW excludes OTP load because it is already included in OTP's network load under Midwest ISO OATT;	Otter Tail Power Company	Otter Tail Power	Otter Tail Power
320	Carve Out	0.00	GFA No. 274 and 320 are the same contract. Maximum Cumulative MW reported in GFA No. 274	Otter Tail Power Company	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
321	Carve Out	2.50	Maximum MW excludes OTP load because it is already included in OTP's network load under Midwest ISO OATT	Otter Tail Power Company	N/A	N/A
323	Carve Out	188.00	GFAs 323 & 390 are related three-party contracts.	Otter Tail Power Company	N/A	N/A
324	Already TEMT	0.00	Both parties, NSP & OTP, report the load as network load under Midwest ISO OATT	Otter Tail Power Company	N/A	N/A
331	Carve Out	423.00	Maximum MW listed in GFA No. 331 is a placeholder for GFA Nos. 331 - 341. 423 MW approximates Southern Illinois Power Coop generating capability as the best available information. 423 MW is not the maximum MWs transmitted under each relevant GFA.	Southern Illinois Power Coop	N/A	N/A
332	Carve Out			Southern Illinois Power Coop	N/A	N/A
333	Carve Out			Southern Illinois Power Coop	N/A	N/A
334	Carve Out			Southern Illinois Power Coop	N/A	N/A
335	Carve Out			Southern Illinois Power Coop	N/A	N/A
336	Carve Out			Southern Illinois Power Coop	N/A	N/A
337	Carve Out			Southern Illinois Power Coop	N/A	N/A
338	Carve Out			Southern Illinois Power Coop	N/A	N/A
341	Carve Out			Southern Illinois Power Coop	N/A	N/A
342	Option B	0.00	GFA Nos. 141,188 and 342 are all the same contract. GFA No. 342 covers service from Hoosier to SIGECO. Historic data shows 0 for Maximum MW	Southern Indiana Gas & Electric		
343	Option B	559.00	Maximum MW reported as 739. 180 MWs excluded from Maximum MW because it is for sales from Alcoa to SIGECO. Assumption is that delivery by Alcoa will be to Alcoa/SIGECO border and therefore there will be no service over Midwest ISO facilities.	Southern Indiana Gas & Electric	Southern Indiana Gas & Elec Co	Southern Indiana Gas & Elec Co
344	Carve Out	0.00	Maximum MW reported in companion GFA Nos. 144, 185, 200, 405 & 416	Wabash Valley Power	N/A	N/A
346	Option A/B	0.00	GFA Nos. 142 and 346 are the same contract; Maximum Cumulative MW reported in GFA No. 142	Wabash Valley Power		
347	Option A	0.00	GFA Nos. 144, 188 and 347 are all the same contract;	Wabash Valley Power		
352	J & R	2.73		Xcel - NSP	NSP	WAPA
354	J & R	1.85		Xcel - NSP	NSP	WAPA
355	Option B	5.63		Xcel - NSP	NSP	NSP
357	Option B	5.91		Xcel - NSP	NSP	NSP
358	Option B	10.93		Xcel - NSP	NSP	NSP
359	Option B	14.34		Xcel - NSP	NSP	NSP
360	Carve Out	8.62		Xcel - NSP	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
361	J & R	2.50		Xcel - NSP	NSP	WAPA
362	Option B	247.00	Maximum MW is largest capacity listed in historic data provided for MPPA load.	Xcel - NSP	Minnesota Muni Pwr Agency	Minnesota Muni Pwr Agency
363	Option B	1.97		Xcel - NSP		
364	Carve Out	8.07		Xcel - NSP	N/A	N/A
365	Carve Out	1.93		Xcel - NSP	N/A	N/A
366	J & R	0.59		Xcel - NSP	Northwestern Wisconsin Elec Co	Northwestern Wisconsin Elec Co
367	Carve Out	200.00		Xcel - NSP	N/A	N/A
368	Carve Out	200.00	Maximum MW reported 200+200 MWs, but that double counts the MW for this summer/winter exchange	Xcel - NSP	N/A	N/A
369	Carve Out	300.00	Maximum MW is taken from 1995-2014 data	Xcel - NSP	N/A	N/A
370	Carve Out	50.00	Maximum MW reported has 4 sink points of 25MW, but that double counts contract capacity since the sink points vary by season (summer/winter)	Xcel - NSP	N/A	N/A
371	Will Expire	0.00	To expire before 3/1/05	Xcel - NSP		
372	Option B	62.00		Xcel - NSP	Wisconsin Public Pwr	Wisconsin Public Pwr
373	Option B	123.00		Xcel - NSP	Wisconsin Public Pwr	Wisconsin Public Pwr
374	J & R	0.00		Xcel - NSP	Xcel	Xcel
375	Convert to TEMT	0.00	GFA No. 375 and 376 are related; Intend to convert to TEMT service; Maximum Cumulative MW is listed for GFA No. 376	Xcel - NSP	N/A	N/A
376	Convert to TEMT	2272.50	GFA No. 375 and 376 are related; Intend to convert to TEMT service; Maximum Cumulative MW is covered by GFA No. 376	Xcel - NSP	N/A	N/A
377	J & R	214.88		Xcel - NSP	NSP	NSP
378	Option B	1162.00	GFA Nos. 378 and 392 are related; Maximum Cumulative MW reported in GFA No. 378	Xcel - NSP	NSP	NSP
379	J & R	169.00		Xcel - NSP	Central Minnesota Muni Pwr	Central Minnesota Muni Pwr
381	J & R	7.20		Xcel - NSP	NSP	NSP
382	J & R	14.98		Xcel - NSP	NSP	NSP
383	J & R	9.14		Xcel - NSP	NSP	NSP
384	J & R	2.74		Xcel - NSP	NSP	NSP
385	J & R	2.54		Xcel - NSP	NSP	NSP
386	J & R	6.73		Xcel - NSP	NSP	NSP
387	J & R	3.61		Xcel - NSP	NSP	NSP
388	J & R	2.51		Xcel - NSP	NSP	NSP
389	Carve Out	0.00		Xcel - NSP	N/A	N/A
390	Carve Out	0.00	GFAs 323 & 390 are related three-party contracts. Maximum Cumulative MW reported in GFA No. 323.	Xcel - NSP	N/A	N/A
391	Carve Out	36.75		Xcel - NSP	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
392	Option B	0.00	GFA Nos. 378 and 392 are related; Maximum Cumulative MW reported in GFA No. 378	Xcel - NSP	Southern Minnesota Muni Pwr Agency	Southern Minnesota Muni Pwr Agency
394	Carve Out	1.30		Alliant Energy - IPL	N/A	N/A
395	Carve Out	102.50		Alliant Energy - IPL	N/A	N/A
399	Option A	0.00	GFA Nos. 399 and 417 are the same contract. Maximum Cumulative MW included in related GFA No. 188.	Cinergy - PSI		
401	J & R	129.00		GridAmerica - Ameren	Ameren	Ameren
403	J & R	62.00	Maximum MW excludes 38 MW associated with entitlement capacity Associated provides to Ameren	GridAmerica - Ameren	Associated Electric Coop / Union Elec	Associated Electric Coop / Ameren
405	J & R	58.00	GFA Nos. 405 and 427 are the same contract; Maximum Cumulative MW reported in GFA No. 405	GridAmerica - Ameren	Wabash	Wabash
406	Option B	0.00	GFA Nos. 222 and 406 are the same contract; GFA No. 448 is a companion; Maximum Cumulative MW reported in GFA No. 222.	GridAmerica - Ameren		
407	J & R	160.00		GridAmerica - Ameren	Union Electric	Ameren
409	J & R		Parties reported MWh. Directed to report MW.	GridAmerica - ATSI (First Energy)	FirstEnergy	FirstEnergy
410	J & R	50.00		GridAmerica - ATSI (First Energy)	FirstEnergy	FirstEnergy
411	J & R	677.50	Maximum MW does not include service from AMP-Ohio (City) to CEI because Midwest ISO facilities are not used	GridAmerica - ATSI (First Energy)	Cleveland Electric Illuminating Co	Cleveland Electric Illuminating Co
412	Option B	462.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	GridAmerica - ATSI (First Energy)	Ohio Edison Co / Penn Pwr Co	Ohio Edison Co / Penn Pwr Co
413	Option B	450.00		GridAmerica - ATSI (First Energy)	Ohio Edison Co	Mirant
414	Option B	352.00		GridAmerica - ATSI (First Energy)	Cleveland Electric Illuminating Co	FirstEnergy Service Co
415	J & R	0.00	GFA Nos. 410 and 415 are the same contract	GridAmerica - ATSI (First Energy)	FirstEnergy	FirstEnergy
416	Carve Out	0.00	GFA Nos. 416 and 428 same contract. Maximum Cumulative MW reported in GFA No. 428.	GridAmerica - NIPSCO	N/A	N/A
417	Option A	0.00	GFA Nos. 399 and 417 are the same contract. Maximum Cumulative MW included in related GFA No. 188.	Indiana Municipal Power Agency	Cinergy Services	Cinergy Services
418	Option A	463.00		LG&E Energy - KU	LG&E	LG&E
419	Option A	14.00		LG&E Energy - KU	LG&E	LG&E

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
420	Option A	62.00		LG&E Energy - KU	LG&E	LG&E
421	Carve Out	0.00	Related to GFA No. 257; Maximum Cumulative MW reported in GFA No. 257	Michigan Public Power Agency	N/A	N/A
422	Carve Out	0.00	Related to GFA No. 256; Maximum Cumulative MW reported in GFA No. 256	Michigan Public Power Agency	N/A	N/A
423	Carve Out	0.00	See 209 - same contract;	Michigan Public Power Agency	N/A	N/A
424	Carve Out	0.00	See 210 - same contract;	Michigan Public Power Agency	N/A	N/A
425	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 284	Minnesota Power	N/A	N/A
426	Option B	34.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	Southern Indiana Gas & Electric	Southern Indiana Gas & Elec Co	Southern Indiana Gas & Elec Co
427	J & R	0.00	GFA Nos. 405 and 427 are the same contract; Maximum Cumulative MW reported in GFA No. 405	Wabash Valley Power	Wabash	Wabash
428	Carve Out	328.00	GFA Nos. 416 and 428 are the same contract. Maximum Cumulative MW reported in GFA No. 428.	Wabash Valley Power	N/A	N/A
430	Carve Out	19.00		Cinergy - PSI	N/A	N/A
431	Carve Out	13.82		Xcel - NSP	N/A	N/A
432	J & R	0.86	reported by parties in KW	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
433	J & R	1.26	reported by parties in KW	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
434	J & R	0.37		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
435	J & R	2.62		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
436	J & R	0.13		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
437	J & R	0.00	Load included in OTP's network service under Midwest ISO OATT	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
438	J & R	0.00	Load included in OTP's network service under Midwest ISO OATT	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
439	J & R	0.04		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
440	J & R	0.43		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
441	Option B	8.00		City of Columbia, Water & Light Department (Columbia, MO)	Associated Electric Coop	Associated Electric Coop
442	Option B	20.00		City of Columbia, Water & Light Department (Columbia, MO)	University Of Missouri	University of Missouri

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
443	Option B	50.00		City of Columbia, Water & Light Department (Columbia, MO)	City of Fulton, MO	City of Fulton, MO
444	Option B	1005.40		City of Columbia, Water & Light Department (Columbia, MO)		
445	Option B	20.00		City of Columbia, Water & Light Department (Columbia, MO)	City of Columbia, Water & Light Department	City of Columbia, Water & Light Department
446	J & R	2695.00		GridAmerica - Ameren	Union Electric / Ameren	Ameren
447	J & R	20.00		GridAmerica - Ameren	Union Electric	Ameren
448	Carve Out	0.00	GFA Nos. 222 and 406 are the same contract; GFA No. 448 is a companion; Maximum Cumulative MW reported in GFA No. 222.	Illinois Power Co	N/A	N/A
449	Option B	40.00		Illinois Power Co	Commonwealth Edison Co (Exelon)	Commonwealth Edison Co (Exelon)
450	Carve Out until hearing resolved	0.00	Maximum Cumulative MW included in GFA Nos. 273, 309 and 317	Minnesota Power	N/A	N/A