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., PJM Interconnection, L.L.C.	Docket No. ER04-375-017
Midwest Independent Transmission System Operator, Inc.	Docket No. ER04-375-018

ORDER MODIFYING AND ACCEPTING TARIFF FILING

(Issued March 3, 2005)

1. This order addresses the December 30, 2004 filing made jointly by Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, L.L.C. (PJM) (December 30 Filing), in which the two regional transmission organizations (RTOs) propose to coordinate their energy markets as of April 1, 2005, the date that Midwest ISO's energy market is scheduled to commence operations.[1] The December 30 Filing also proposes planning steps to further coordinate ancillary service markets, the allocation of transmission capacity and related financial rights, and otherwise to continue development of a joint and common market covering the RTOs' combined regions. For the reasons described below, we will modify and

[1] The December 30 Filing requested an effective date of March 1, 2005. On January 28, 2005, Midwest ISO filed, in a number of dockets related to its transmission and energy markets tariff (TEMT) and in Docket No. ER04-375-018, a motion to change to April 1, 2005 the effective date for the start of financially binding market operations. This change affects coordination of the Midwest ISO and PJM energy markets. On February 17, 2005, the Commission granted the motion for tariff sheets in the TEMT. *Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,169 (2005) (February 17, 2005 Order).

conditionally accept this filing. This order benefits customers by promoting more effective and efficient provision of transmission service.

I. **Background**

2. In a July 31, 2002 Order,[2] addressing proposals by certain companies to join either Midwest ISO or PJM, the Commission stated that a common market across Midwest ISO and PJM would minimize seams issues created by the companies' choices and allow parties to manage seams issues more efficiently. The Commission then, as a condition of accepting those RTO choices, required Midwest ISO, which had previously committed to institute a locational marginal pricing (LMP)-based market, and PJM to form a functional common market across their combined regions. A further condition required Midwest ISO and PJM to file a joint operational agreement detailing how they will operate at the seams.[3]

3. In a December 31, 2003 filing, Midwest ISO and PJM proposed a Joint Operating Agreement (JOA) to address seams issues. The filing proposed methodologies for coordinating Midwest ISO's then non-market operation with PJM's market-driven operation during Phase 1, the market-to-non-market phase. It also proposed to achieve further coordination during Phase 2, the market-to-market phase, once Midwest ISO had commenced operation of its energy markets. The filing provided that during market-to-market Phase 2, the RTOs' additional cooperative measures would include consistency in calculating LMPs on coordinated flowgates, and coordination to manage congestion on coordinated flowgates.

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[2] *Alliance Companies*, 100 FERC ¶ 61,137 (2002), *order on clarification*, 102 FERC ¶ 61,214, *order on rehearing and providing clarification*, 103 FERC ¶ 61,274, *order denying rehearing and granting clarification*, 105 FERC ¶ 61,215 (2003), *appeal docketed sub nom. American Electric Power Service Corp. v. FERC*, No. 03-1223 (D.C. Cir. Aug 1, 2003) (*Alliance Companies* Order).

[3] *Id*., 100 FERC ¶ 61,137 at P 38, 40, 48.

4. The Commission modified and conditionally accepted the JOA on March 18, 2004, with clarifications on August 5, 2004.[4] In the JOA Order, the Commission endorsed the objectives of the Phase 2 provisions but found that specific consideration of these provisions would be premature. It therefore accepted the Phase 2 provisions, subject to the RTOs making a filing, at least 60 days prior to the commencement of Phase 2, revising the JOA to provide more detail on Phase 2 and addressing the intervenors' concerns. The Commission stated that such filing would be subject to further Commission orders.[5]

5. The JOA Order required the RTOs to file, as part of a revised JOA, their market-to-non-market coordination protocols, known as the Congestion Management Process (CMP), whose provisions the RTOs had incorporated into the JOA by reference.[6] It also required the RTOs, among other compliance actions, to file informational reports discussing their progress in implementing the JOA.[7] These reports were to be combined with the reports that the RTOs already were required to make every 60 days concerning progress toward achieving a common market across the Midwest ISO and PJM regions, pursuant to the *Alliance Companies* Order.[8]

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[4] *Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,251 (JOA Order), *order on reh'g and clarification*, 108 FERC ¶ 61,143 (August 5, 2004 Order), *order on clarification and denying reh'g*, 109 FERC ¶ 61,166 (November 18, 2004 Order) (2004). For more detailed background, *see* JOA Order at P 2-6 and August 5, 2004 Order at P 2-7. *See also PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,087 at P 3-9 (2004).

[5] JOA Order at P 81.

[6] The CMP was originally called the Seams White Paper. Consistently incorporated into the JOA as Attachment 2, the CMP has been revised several times. In their April 2, 2004 compliance filing, made pursuant to the JOA Order, the RTOs revised the JOA by filing Original Sheets Nos. 102-244 to Rate Schedule No. 5 of Midwest ISO and Rate Schedule No. 38 of PJM, comprising version 4.01 of the CMP. In their September 7, 2004 compliance filing, made pursuant to the August 5, 2004 Order, the RTOs filed further revisions comprising version 4.02.

[7] JOA Order at P 105.

[8] *Alliance Companies* Order, 100 FERC at 61,530.

6. In the August 5, 2004 Order, the Commission clarified that Midwest ISO and PJM were to file the required Phase 2 revisions between 60 and 120 days prior to the requested effective date for Phase 2. The Commission also expanded the required periodic progress reports to include discussion regarding the implementation of the CMP.[9]

7. On October 28, 2004, in a proceeding concerning integration into PJM of Commonwealth Edison Company (ComEd),[10] the Commission repeated its requirement that Midwest ISO and PJM implement a joint and common market, established in the *Alliance Companies* Order. The Commission referenced the filing that the RTOs were already required to make before implementing Phase 2, pursuant to the JOA Order and the August 5, 2004 Order, and further required them to add to that filing a detailed timeline of the steps that they anticipated taking to achieve their joint and common market, along with a date certain on which they expected commencement of this market to occur.[11]

8. In the November 18, 2004 Order, clarifying and denying rehearing of the August 5, 2004 Order, the Commission addressed intervenors' questions on how available flowgate capacity would be allocated between the two RTOs, whether by historical use or on a first-come, first-served basis. The Commission concluded that the use of historic network and native load transactions is appropriate for allocation of available capacity between the two RTOs on a forward-looking basis, and for evaluating new requests for transmission service. The Commission relied, in part, on Midwest ISO's and PJM's practices, instituted in August 2004, whereby the RTOs share their allocations of available flowgate capacity so that a new transmission request is not denied when sufficient capacity is available to approve the request.[12] The Commission directed Midwest ISO and PJM to indicate, in their periodic JOA progress reports, instances when an RTO's refusal to share its allocation of available capacity on a coordinated flowgate caused denial of a request for transmission service. The Commission noted that the RTOs had instituted a stakeholder process to consider revisions to the JOA allocation

[9] August 5, 2004 Order, 108 FERC ¶ 61,143 at P 42, 45, 59.

[10] *PJM Interconnection, L.L.C.*, 109 FERC ¶ 61,094 (2004) (October 28, 2004 Order).

[11] October 28, 2004 Order, 109 FERC ¶ 61,094 at P 16.

[12] November 18, 2004 Order, 109 FERC ¶ 61,166 at P 23-26.

methodology and directed the inclusion, in these periodic reports, of status reports on use of the stakeholder process to revise the JOA allocation methodology.[13]

9. Also on November 18, 2004, in a proceeding addressing rate pancaking under the RTOs' open access transmission tariffs,[14] the Commission addressed intervenors' concerns about the need for the RTOs to integrate their financial transmission rights (FTR) allocation and auction procedures, and about the need to eliminate pancaking of rates for scheduling and other ancillary services under each RTO's tariff for service to loads within the RTOs' combined regions. The Commission stated that these issues were better addressed in the context of Midwest ISO and PJM's forthcoming filing indicating the steps needed to achieve a joint and common market and proposing a timeline for completion. The Commission directed the RTOs to specifically address, in their forthcoming filing, their plans for resolving these issues.[15] The Commission advised the intervenors to raise their concerns in response to that filing, due on December 31, 2004.

II. <u>December 30 Filing</u>

10. The December 30 Filing proposes a new attachment to the JOA, entitled "Interregional Coordination Process" (ICP),[16] that sets forth the Phase 2 market-to-market coordination protocols between Midwest ISO and PJM. In addition, the RTOs propose conforming revisions to the body of the JOA necessary to implement the market-to-market coordination protocols. The December 30 Filing also addresses the requirements of the October 28, 2004 Order and the Transmission Rates Order by discussing the steps the RTOs believe necessary for achieving a joint and common market and a timeline for taking those steps. The RTOs' proposals with respect to Phase 2 coordination and their plans to achieve a joint and common market are each discussed further below.

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[13] *Id*. at P 28, 30.

[14] *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,168 (2004) (Transmission Rates Order), *reh'g pending*.

[15] *Id*. at P 76, 78.

[16] Attachment 3 to the JOA, "Interregional Coordination Process," Version 1.8, proposed Original Sheet Nos. 245-66 to Rate Schedule No. 5 of Midwest ISO and Rate Schedule No. 38 of PJM.

11. On January 28, 2005, Midwest ISO filed a motion, in several dockets, asking the Commission to postpone the start of its energy market operations and, in Docket No. ER04-375-018, to change the requested effective date for the start of Phase 2 of the JOA from March 1, 2005, as stated in the December 30 Filing, to April 1, 2005.

12. In both the December 30 filing and its January 28, 2005 motion, Midwest ISO asks the Commission to waive the service requirements stated in Rule 2010(a) of the Commission's Rules and Regulations, 18 C.F.R. § 385.2010(a) (2004), regarding service of paper copies of the filing. Midwest ISO explains that it has made service electronically, has posted the filing on its website, and will make paper copies available upon request. PJM describes, in the December 30 Filing, the entities whom it has served.

III. Notice and Responsive Filings

13. Notice of the December 30 Filing was published in the *Federal Register*, 70 Fed. Reg. 3,010 (2005), with comments, protests, and interventions due on or before January 21, 2005. Wisconsin Public Service Corporation and Upper Peninsula Power Company (together, Wisconsin Public Service) jointly filed comments and a protest. Exelon Corporation (Exelon) and Wisconsin Electric Power Company (Wisconsin Electric) filed comments. On February 4, 2005, Midwest ISO filed an answer to each of these parties.

IV. Discussion

A. Procedural Matters

14. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(3) (2004) prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Midwest ISO's February 4, 2005 answer because it has provided information that assisted us in our decision-making process.

15. The Commission granted Midwest ISO's January 28, 2005 motion for changes of effective date to April 1, 2005, with respect to its transmission and energy markets tariff.[17] Because the start of Phase 2 operations is tied to the effective date of financially binding energy market operations for Midwest ISO, we will grant the requested effective date for the tariff sheets in the December 30 Filing, including those addressing the commencement of Phase 2, to coincide with the start of financially binding energy market operations.

[17] *See supra* note 1, and February 17, 2005 Order, 110 FERC ¶ 61,169 at Ordering Paragraph (A).

16. We will grant Midwest ISO's requests for waiver of Rule 2010 concerning service of paper copies.

B. <u>Phase 2 Market-to-Market Interregional Coordination Process</u>

17. For Phase 2 market-to-market coordination, Midwest ISO and PJM propose to use market-based congestion management techniques to help manage flows in each RTO's market that affect constrained flowgates on the other RTO's system, on a day-ahead and real-time basis, and they provide an example to illustrate the real-time coordination and associated settlements. The RTOs also propose procedures for taking each RTO's flow entitlements into account when determining simultaneous feasibility of financial transmission rights (FTRs). The December 30 Filing sets forth these proposed market-to-market coordination protocols in a new attachment to the JOA, entitled "Interregional Coordination Process."

18. The RTOs explain that the proposed market-to-market coordination builds upon the market-to-non-market coordination protocols currently being implemented through the Congestion Management Process attachment to the JOA. These existing protocols identify the transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market and terms them "reciprocal coordinated flowgates" (RCFs).[18] They describe how market flow impacts will be managed on an interregional basis to enhance the effectiveness of the existing North American Electric Reliability Council (NERC) interregional congestion management process. They also provide a process for establishing flow entitlements for network and native load transactions in one region on the RCFs in an adjacent region. Under these market-to-non-market coordination protocols, responsibility to redispatch or curtail transactions is shared pro rata in proportion to each RTO's flow entitlements, and each RTO independently curtails transactions or redispatches its market to meet its responsibility to reduce flows on the constraint.

19. In the December 30 Filing, the RTOs attempt to adapt the market-to-non-market coordination currently in place to reflect additional efficient market-to-market

[18] An RCF is defined to be either (1) a coordinated flowgate affected by the transmission of energy by both RTOs, or by both parties and one or more reciprocal entities or (2) a flowgate which both RTOs mutually agree should be a coordinated flowgate, and for which reciprocal coordination will occur. An RCF may be under the operational control of one RTO, or it may be under the operational control of a third party that has signed a reciprocal coordination agreement. The third party is referred to as a "reciprocal entity." *See* section 6.1 of the JOA.

coordination that will be possible after implementation of Midwest ISO's markets. The basic premise is to establish procedures that allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. The joint management of constraints is designed to lower the cost of the congestion, and to provide coordinated pricing at market boundaries. Thus, in contrast to the current market-to-non-market coordination, where each RTO independently curtails transactions or performs redispatch to meet its responsibility to reduce flows on the constraint, the proposed market-to-market coordination protocols provide for coordinated redispatch between the two RTOs on a least-cost basis, with financial settlements through which each RTO is compensated for the redispatch that it provides to the other RTO.

20. The market-to-market coordination can be sub-divided into three types of coordination: that of the real-time energy market, day-ahead market and for FTR allocation and auction.

1. Real-Time and Day-Ahead Market Coordination

a. Proposal

i. Real-time Market Coordination

21. The December 30 Filing provides that the RTOs will exchange topology information to ensure that their respective market software is consistent. Specific RCFs are identified. The "list of RCFs will be limited to only those for which at least one generator in the adjacent market has a significant power distribution factor (DFAX), sometimes called a 'shift factor,' with respect to serving load in that adjacent market (e.g., currently five percent)."[19] At this point, approximately 330 RCFs have been identified. The RTOs will monitor these RCFs to measure the impact of market flows and loop flows from adjacent regions. The RTO responsible for monitoring flows on a particular flowgate is referred to as the "monitoring RTO," and the neighboring RTO with flows that affect that flowgate is referred to as the "non-monitoring RTO." When any of the RCFs under a monitoring RTO's control is identified as experiencing a transmission constraint, that RTO will enter the RCF into its security constrained economic dispatch software, and set the flow limit equal to the appropriate facility rating. The monitoring RTO will then notify the non-monitoring RTO of the transmission constraint limitation/violation. The non-monitoring RTO will enter the RCF into its dispatch software, setting the flow limit equal to its current market flow on that flowgate.

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[19] Interregional Coordination Process, Original Sheet No. 248.

22. If there is a constraint on an RCF in real time, the monitoring RTO will transmit information to the non-monitoring RTO on the constraint shadow price, the current market flow contribution by the monitoring RTO at that flowgate, and the number of megawatts by which it is (initially) requesting the non-monitoring RTO to reduce its flow over the RCF. The non-monitoring RTO will transmit its constraint shadow price and its current market flow to the monitoring RTO, which will then perform an analysis to compare the constraint shadow price information for each RTO, in order for the monitoring RTO to determine the cheapest way of managing the constraint. Each RTO will redispatch in accordance with this least cost solution. If required, the monitoring RTO may request the non-monitoring RTO to provide additional constraint shadow price information, and ultimately may request more flow relief.

23. The process of comparing the shadow prices will continue over the next several dispatch cycles. The monitoring RTO may request the non-monitoring RTO to adjust its flow limit up or down, and the monitoring RTO will make corresponding changes to its own dispatch, with the intent to equalize the constraint shadow prices in the two RTOs.

24. The market settlements process provides that if the real-time market flow of the non-monitoring RTO on a constrained RCF is greater than the flow entitlement on that RCF plus the approved MW adjustment from day-ahead market coordination (discussed in the Day-ahead Market Coordination section), then the non-monitoring RTO will pay the monitoring RTO for congestion relief provided by the monitoring RTO to sustain the higher level of real-time market flow. Payments will be calculated on an hourly-integrated basis. This payment will be calculated:

> Payment = (real-time market flow MW – (firm flow entitlement MW + approved MW)) * transmission constraint shadow price in monitoring RTO's dispatch solution.

25. If the real-time market flow of the non-monitoring RTO on a constrained RCF is less than its firm flow entitlement on that RCF plus the approved MW adjustment from day-ahead coordination, the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO using the constraint at a level below the firm flow entitlement. The payment will be calculated:

> Payment = ((firm flow entitlement MW + approved MW) - real-time market flow MW) * transmission constraint shadow price in non-monitoring RTO's dispatch solution.

26. Each RTO's software will calculate LMPs for its interface(s) with the other RTO. In doing so, the software will calculate the prices at one or more "proxy buses" that serve to reflect the economic value of imports to or exports from the neighboring RTO. Under the market-to-market rules, the RTOs will also coordinate their proxy bus models to

better coordinate their border prices and to enable consistency with prices at physical buses on both sides of the border.[20] The proxy bus models must be coordinated to the same degree of granularity for this to occur. Under the RTOs' proposal, consistent pricing does not mean that proxy bus prices will be the same, but rather that the proxy bus price one RTO calculates for another RTO reflects the nature of the congestion on both RTOs' systems. The RTOs state that as the market-to-market coordination process continues to evolve, "it may be possible to get to the point that each RTO's proxy bus for the other is defined on the RTO border, and the proxy bus prices are actually the same or consistently close. This will require coordination beyond merely operating for constraints on each other's systems, to include tightly coordinating the economic dispatches themselves."[21]

ii. <u>Day-Ahead Market Coordination</u>

27. The day-ahead energy market coordination focuses primarily on ensuring that the scheduled flows on all RCFs (identified as for real-time market coordination) are limited to no more than the firm flow entitlements for each RTO in the day-ahead market. Each RTO will model all RCFs for which it is the reliability coordinator, with the limit set equal to the applicable facility limit less the firm flow entitlement of the non-monitoring RTO. The non-monitoring RTO will model the RCF with the limit set equal to its firm flow entitlement for that RCF. Either RTO may request that the day-ahead flow limit be raised above its firm flow entitlement.[22] The RTOs propose that this protocol should be used infrequently and only when the need for additional assistance is predictable on a day-ahead basis. The day-ahead energy market redispatch protocol may be implemented in the day-ahead energy market upon the request of either RTO if the adjacent RTO verifies that such day-ahead redispatch is possible. The request must be made by 0700

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[20] The proxy bus models will use a flow-weighted average price model at common tie points at the market borders. In the day-ahead market and in the FTR models the flow weighted proxy bus definitions will be used at all times. In the real-time market if the scheduled flow and actual flow are consistent at the proxy bus location, then the flow-weighted average price will be used. If there are significant loop flows at any of the proxy bus border points, then the proxy bus price will be changed to reflect actual real-time flow patterns.

[21] Interregional Coordination Process, Original Sheet No. 249.

[22] Interregional Coordination Process, Original Sheet No. 252.

EST on the day before the operating day, and if the responding RTO agrees, it must communicate that by 0800 EST.

28. The market settlements for day-ahead congestion relief will be executed in a manner similar to that for the real-time congestion relief. The requesting RTO will pay the responding RTO the approved day-ahead adjustment to the volumes at the RCF multiplied by the responding RTO's RCF constraint shadow price. The payment will be calculated based upon the hourly day-ahead market results. If such congestion relief is performed on a day-ahead basis, then the real-time flow entitlement for the affected hours in the corresponding real-time market will be adjusted accordingly.

b. <u>Comments</u>

29. Exelon supports the proposed Phase 2 market-to-market provisions and encourages approval by the Commission before the requested effective date. It states, however, that section 6.1 of the JOA should be revised further to clarify the definition of an RCF. In particular, it does not believe that the RTOs' proposed revision to section 6.1 effectively clarifies, as the RTOs stated in their transmittal letter was their intent, that the procedures applicable to RCFs do not apply to flowgates under the operational control of third parties unless those parties agree to either the market-to-market or the market-to-non-market coordination protocols, as reciprocal entities. As proposed by the RTOs, section 6.1 provides that a coordinated flowgate may be under the operational control of a third party and an RCF is defined as a coordinated flowgate "affected by the transmission of energy by both Parties, or by both Parties and one or more other Reciprocal Entities." Exelon says that this wording means that if PJM and Midwest ISO affect a coordinated flowgate by the transmission of energy and that flowgate is under the operational control of a third party that is not a reciprocal entity, it becomes an RCF, which it says is exactly what PJM and Midwest ISO are trying to avoid. Exelon recommends the addition of the following language: "An RCF must be under the operational control of one of the Parties or must be under the operational control of a third party Reciprocal Entity" after the first sentence of the definition of RCF in section 6.1.

30. Wisconsin Public Service says that the December 30 Filing moves in the right direction in providing additional detail on the plan for market-to-market real-time and day-ahead coordination. However, it has several problems with the filing. Wisconsin Public Service says that the RTOs do not demonstrate that the costs of interregional congestion will be fairly allocated among neighboring regions that have over 300 RCFs. Specifically, it says that the proposal does not explicitly call for the implementation of consistent and compatible day-ahead and real-time software systems in the two markets, and without it Wisconsin Public Service believes one of the key ingredients for the successful functioning of the proposed market-to-market coordination is lacking. Because the exchange of shadow prices and load data calculated by each RTO's dispatch

system is used in an iterative process to roughly equalize the LMPs on either side of the constraint, Wisconsin Public Service believes that use by the RTOs of consistent (if not identical) real-time security constrained economic dispatch software is needed, and that the LMP calculations must be consistent for the system to fairly allocate costs. It says that Midwest ISO has not provided assurances that its security constrained economic dispatch software is reliable or consistent with PJM's existing systems. It is concerned that there is insufficient time prior to the scheduled Midwest ISO market start date to determine whether the real-time security constrained economic dispatch software of Midwest ISO is compatible and consistent with PJM software that has been functioning for several years.

31. Wisconsin Public Service says that because the two RTOs have not demonstrated that the two software systems are functionally similar, or that Midwest ISO's security constrained economic dispatch software is accurate, they have not yet established that there will be an efficient interregional redispatch solution for a given RCF constraint. Instead, it says, market participants are asked to "acquiesce to a complex interchange of market data during binding congestion, based on simplistic charts and the 'intent' of the RTOs to 'attempt to make [shadow prices] comparable within a reasonable tolerance.' These assurances do not ensure that the associated energy prices and the processes used to calculate them will be just and reasonable." It says that Midwest ISO and PJM must either show that their proposal will generate a just and reasonable rate, by showing that the LMP prices in the two markets can be reconciled through adequate safeguards such as compatible software, or if they cannot provide such functional assurances, they must demonstrate to the Commission that the anticipated price differences will fall "within a reasonable tolerance" with adequate supporting data. Wisconsin Public Service states that the process of exchanging data about RCFs every 15 to 30 minutes will be overwhelming unless the systems are compatible.

32. Wisconsin Public Service says that the filing is unclear on which settlement system the two RTOs will use to determine the payments due under the proposed market-to-market coordination protocols. These calculations must be made on an hourly integrated basis. It says that because, under the proposed market-to-market coordination protocols, the prices are the determinant that shows when the congestion price allocation has been resolved, the price calculations must be compatible and consistent. It says that while the examples contained in the filing are helpful, the RTOs do not explain the financial settlement systems that are to be used to reconcile the payments between the two RTOs. Midwest ISO must put in place adequate protections so that its market participants' shares of congestion management settlement fees are calculated on a comparable basis to those of the PJM market participants. Thus, it says, the Commission should order PJM and Midwest ISO to implement compatible settlement and security

constrained economic dispatch software systems and demonstrate their compliance in a subsequent compliance filing.

33. Wisconsin Public Service also protests that the December 30 Filing does not adequately describe the method for defining proxy bus prices. It cites the statement in the RTO's proposal that "for the market-to-market coordination to function properly, the proxy bus models for PJM and MISO must include the same level of detail, and modeling approaches must be similar, so that prices are consistent."[23] Wisconsin Public Service agrees that the data used in the market-to-market protocols must be calculated consistently by the two RTOs. However, it says, it is not clear how the RTOs define proxy buses, how many will be defined, or their locations. It states that these issues should be resolved in the market-to-market protocols so that market participants can assess the impact of the proposed JOA revisions. In addition, Wisconsin Public Service argues that the JOA does not discuss the methodology that Midwest ISO will use to define proxy buses for non-market entities. It says that the Commission should order Midwest ISO and PJM to describe all aspects of their proxy bus proposal, including the treatment of proxy buses for non-market entities.

34. Wisconsin Public Service makes several other specific comments regarding the JOA: (1) the filing does not state whether the RTOs will post their available flowgate capacity (AFC) or available share of total flowgate capacity values and, if not, why not; (2) the filing does not explain changes proposed to Midwest ISO's AFC process once its markets start; (3) the filing does not clarify whether PJM would change its AFC process to accommodate the start of Midwest ISO's markets; and (4) the RTOs are not clear on whether they will post their current policies on sharing unused allocation, or under what time frame that sharing applies on their open access same-time information system (OASIS) sites. Wisconsin Public Service argues that all unresolved issues should be resolved prior to the Midwest ISO market start date.

35. Further, Wisconsin Public Service identifies a number of "conforming changes" that it feels need resolution before the market-to-market protocols can be implemented. First, it states that revisions to billing practices upon agreement between the RTOs, as contemplated in section 16.2 of the JOA, should be subject to filing at the Commission. Next, it lists a number of issues that it says were left unresolved at a December 9, 2004 Midwest ISO Congestion Management Process meeting in Carmel, Indiana, including: the lack of an allocation for third party flowgates, eliminating expansion margins beyond

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[23] Wisconsin Public Service's January 21, 2005 filing at 8, citing section 2 of the Interregional Coordination Process.

the first six months; removing Capacity Benefit Margin from AFC calculations; clarifying whether sharing of flowgate allocation includes both point-to-point and network transmission services; accommodating Mid-Continent Area Power Pool Schedule F; and ensuring that parties developing new transmission facilities receive credits. Wisconsin Public Service emphasizes that, at a minimum, every aspect of the JOA that is needed to implement market-to-market transactions must be in place before the start date for market-to-market coordination

c. Answering Comments

36. Midwest ISO says that Exelon's request to further restrict the application of RCFs in section 6.1 of the JOA fails to consider that the JOA covers both the market-to-non-market and market-to-market congestion management processes, and would unreasonably restrict the ability of the parties to deal with unanticipated reliability threats. Until Phase 2 begins with the initiation of Midwest ISO's energy markets, the market-to-non-market coordination protocols will still be in effect for the RCFs managed under the market-to-non-market operations, and the parties will continue to model some RCFs that are not under functional control of PJM or Midwest ISO. In addition, Midwest ISO says that it and PJM have already determined that RCFs should not be recognized when the flowgate is external to both Midwest ISO and PJM in the market-to-market context:

> As a further clarification, PJM and MISO will only be performing market-to-market coordination on RCFs that are owned and controlled by PJM or MISO. PJM and MISO will not be performing market-to-market coordination on RCFs that are owned and controlled by third parties or on flowgates that are only considered to be coordinated flowgates.[24]

37. Midwest ISO says that the amendment to section 6.1 of the JOA submitted in the December 30 Filing is intended to communicate that under normal circumstances, a flowgate will not become an RCF unless it passes the tests set out in the market-to-non-market coordination protocols contained in the Congestion Management Process, or the market-to-market coordination protocols contained in the Interregional Coordination Process, or, by mutual agreement of the parties (including a third-party reciprocal entity having an impact on that flowgate). Such circumstances can present themselves on short notice and have the potential to create significant reliability problems. Midwest ISO says that in two stakeholder workshops, PJM and Midwest ISO were clear that they did not

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[24] Interregional Coordination Process, Original Sheet No. 248.

intend to recognize RCFs outside their control as a matter of efficient market policy, but they say that the language offered by Exelon goes too far in tying the hands of the RTOs in their role as reliability coordinators.

38. Midwest ISO says that all of the issues raised by Wisconsin Public Service are without merit and were raised in stakeholder meetings.[25] While discussion of some issues resulted in changes agreed to by Midwest ISO and PJM, other issues were deferred until after the start of Midwest ISO's energy market. Midwest ISO does not believe that any of these issues are critical to the smooth integration of the markets in the Phase 2 market-to-market coordination. It notes that the proxy bus issue was part of the Congestion Management Process meeting presentation on market-to-market coordination at the December 9, 2004 meeting. It generated a number of comments on how the proxy bus and its price are determined. During the January 21, 2005 follow-up meeting there was limited discussion of the proxy bus issue, as the proxy bus is not used in the market-to-market process. Instead the shadow price is the key component in the market-to-market implementation.

39. With respect to the other issues raised by Wisconsin Public Service, Midwest ISO says that the JOA does not require posting of available shares of total flowgate capacity. However it says that both it and PJM are posting AFC values and available shares of total flowgate capacity on their OASIS sites. Midwest ISO says that the only change that has been made to the AFC process is to estimate how generators will be dispatched under Midwest ISO's energy market. In particular, Midwest ISO is replacing the use of merit order files for each control area with projections based on cost information to determine generator dispatch in the market.

40. Midwest ISO says that it is unclear what is meant about PJM changing its AFC process to accommodate Midwest ISO's energy market. PJM has always operated a market, and it developed its current AFC process to accommodate the expansion of its own energy market to include American Electric Power Service Corp. (AEP), ComEd, Duquesne Light Company, and Dayton Power and Light Company. There is no logical reason, Midwest ISO says, for PJM to have to change its AFC process for the Midwest ISO market. Midwest ISO also says that it and PJM are not opposed to posting the current methodology for sharing unused allocations. The two parties distributed the

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[25] Issues were raised primarily in the December 9, 2004 and January 21, 2005 Congestion Management Process meetings.

current process in the material that went to participating stakeholders for the January 21, 2005 follow-up meeting, and it is currently posted on the Midwest ISO website under the meeting material.

41. In response to concerns expressed about the readiness of Midwest ISO's systems, Midwest ISO notes that NERC conducted the Phase 2 audit of its system, from January 24 to 28, 2005, and concluded that there were no deficiencies and made no recommendations for improvement. The ability of Midwest ISO to report market flows to, and communicate with the NERC Interchange Distribution Calculator (IDC) is now established. Midwest ISO also notes that its unit dispatch system is the same one used by PJM, and that the parties use the same vendor for the real-time and day-ahead software. The two RTOs jointly developed the specification requirements for the market-to-market implementation and submitted them to the vendor. Several market-to-market implementation teams, including information technology personnel, have met by phone and face-to-face on a regular basis since the beginning of the JOA process. All of the software compatibility issues raised by Wisconsin Public Service are non-issues according to Midwest ISO.

42. Midwest ISO also says that the comments of Wisconsin Public Service on market settlement miss the point. Taken in context, section 16.2 of the JOA deals with invoices, and payment of invoices, between the two RTOs. It does not affect revenue distribution to transmission owners or market settlements with market participants. Its only purpose is to give the parties the flexibility, upon mutual agreement, to change the billing and payment cycle for any obligations they may incur between themselves under the JOA.

43. Midwest ISO says that the "conforming changes" Wisconsin Public Service lists on page 7 of its comments are all Phase 1 proposed changes that were discussed at both the December 9, 2004 stakeholder meeting and at the January 21, 2005 follow-up meeting. They are not items that must be resolved before Phase 2 begins. With the exception of the credits for new transmission facilities, Midwest ISO and PJM have both agreed to these changes and will implement them as soon as software changes are in place. With regard to "credits" for new transmission facilities, Midwest ISO has already presented the concepts before stakeholders attending the January 21, 2005 follow-up meeting and will form a group of reciprocal entities to define the allocation adjustment process for new transmission facilities.

d. <u>Commission Discussion</u>

44. We do not agree with Exelon that the definition of RCF must be amended to include Exelon's proposed language designed to clarify that a RCF must be under the operational control of one of the RTOs or a third party reciprocal entity. As Midwest ISO indicates in its answering comments, the language under the JOA must bridge both

Phase 1 and Phase 2 of the JOA. In addition, the language in section 1 of the proposed market-to-market protocols, Original Sheet No. 248, indicates that PJM and Midwest ISO will be performing market-to-market coordination only on RCFs that are owned and controlled by PJM or Midwest ISO. PJM and Midwest ISO will not be performing market-to-market coordination on RCFs that are owned and controlled by third parties or on flowgates that are only considered to be coordinated flowgates.

45. However, it is somewhat unclear from the December 30 Filing how RCFs will be determined. In particular, the language on Original Sheet No. 248 refers to the need for RCFs to have a generator in the adjacent market with significant power distribution factors "(e.g., currently five percent)," while RCFs are defined in the market-to-market protocols as flowgates for which reciprocal entities have generation that has more than a five percent power DFAX on the flowgate. Meanwhile, section 3 of the market-to-non-market protocols describes the adoption of a five percent standard with the agreement to adopt a lower threshold at the time NERC implements the use of a lower threshold in the transmission loading relief (TLR) process and establishes certain other tests for determining if generators have significant impacts upon the flowgate. Thus, it is not clear if the standard is five percent or more than five percent, nor if this is a firm standard, or something that may be changed within the terms of the JOA. It is also unclear if the RTOs intend to adopt the additional tests for RCF determination set out in section 3 of the market-to-non-market protocols for RCF determination in the market-to-market protocols, or if they intend to establish separate criteria in the market-to-market protocols. Accordingly we will require Midwest ISO and PJM to further clarify the criteria used to designate RCFs under the market-to-non-market and market-to-market protocols in the compliance filing ordered below.

46. In addition, the power distribution factor or DFAX used to designate RCFs should be more clearly defined. It is also not clear if it is the same as the Generation Load Distribution Factor referenced in the market-to-non-market protocols. If it is, a common terminology should be used in the JOA, with its meaning defined therein. We direct the RTOs to provide such additional clarification in the compliance filing ordered below.

47. Wisconsin Public Service has provided no substantiation that Midwest ISO's and PJM's software systems are not functionally similar, or that Midwest ISO's security constrained economic dispatch software is inaccurate. As Midwest ISO notes, it will be using the same unit dispatch system as PJM, which has operated an LMP-based market for several years, and the RTOs are using the same vendor for the real-time and day-ahead software. The RTOs have jointly developed the specifications for the market-to-market implementation. Their implementation teams have met on a regular basis to ensure that the systems are compatible, and that they will work well together. Thus, we believe the software systems are sufficiently compatible at this time. In addition, the

JOA is a step towards the joint and common market and efficient dispatch across the regions; it is not, in itself, the final goal. While there may be ways to achieve tighter coordination of the RTOs' market software systems, such avenues will have to be weighed against the additional time and expense they would require. The RTOs will be considering such factors as they contemplate the next steps toward their joint and common market, as discussed below. In the meantime, delaying the start of the Midwest ISO's day 2 market and Phase 2 market-to-market coordination under the JOA would be counter-productive, as it would deny customers throughout the footprints of the two RTOs the benefits of a cheaper dispatch in the near term.

48. Nor do we believe that the RTOs need to use identical software or a single dispatch system in order to provide for fair allocation of congestion costs across the RTO areas. The JOA process is not designed to change the allocation of congestion costs between regions. Instead, it is designed to reduce the costs of congestion in each region, by allowing the RTOs to resolve the congestion in the cheapest manner available from the two dispatching systems, with compensation going to the RTO that decreases its flow across the constraint below its flow entitlement.

49. However, we agree with Wisconsin Public Service that the language in the market-to-market protocols relating to the "intent" of the RTOs to "attempt to make [shadow prices] comparable within a reasonable tolerance" is not sufficiently clear. It does not provide enough detail as to when the iterative process of dispatch coordination (shadow price comparison and associated RTO flow adjustments) will cease. Thus, we direct Midwest ISO and PJM to clarify the JOA to specify the manner in which they decide to stop the iterative dispatch coordination process in the compliance filing ordered below. The process should be consistent for RCFs across the two RTOs.

50. With respect to Wisconsin Public Service's comments that it is not clear which settlement system will be used to determine the payments due under the market-to-market protocols, and the need for protections so that Midwest ISO's market participants' shares of congestion management settlement fees are calculated on a basis comparable to those of PJM market participants, we agree, in part. Section 16.2 deals with invoices, and payments of those invoices, between the RTOs. It does not affect revenue distribution to transmission owners or market settlements with market participants. Its only purpose, which we find to be reasonable, is to give Midwest ISO and PJM the flexibility to change the billing and payment cycles for any obligations they may incur between themselves under the JOA. However, we will require Midwest ISO and PJM to modify the JOA, in the compliance filing ordered herein, to explain how their hourly integrated settlement is performed; particularly to specify what shadow price is used when the shadow prices change throughout the hour.

51. We agree with Wisconsin Public Service that the process by which proxy bus or buses are determined needs to be laid out in more detail. While the shadow price is central to the market-to-market coordination of RCFs, rather than the proxy bus price, proxy bus pricing is an important element of efficient seams management and the market-to-market protocols includes the calculation of the proxy bus price. We believe that the process or factors by which the proxy bus or buses between PJM and Midwest ISO are determined should be clear to market participants. As such, we will require Midwest ISO and PJM to modify the JOA to specify the process or factors for their determination of such proxy buses in the compliance filing ordered below.

52. Wisconsin Public Service raises a number of issues on available flowgate capacity (AFC) and available share of total flowgate capacity which it says needed clarification before the JOA can be considered complete. Midwest ISO, in its answering comments, has provided clarification on these issues. We agree with Midwest ISO that Wisconsin Public Service has not substantiated its call for PJM to be required to change its AFC process for the Midwest ISO market. Thus, we see no reason to delay implementation of the Midwest ISO market or adoption of the market-to-market coordination protocols on this basis. On the issue of posting the current methodology for sharing unused allocations, Midwest ISO says that the RTOs are not opposed to doing so, and that the methodology is currently posted under meeting notes on the Midwest ISO website. We find that market participants would benefit from the methodology for sharing allocations being made transparent. Accordingly, we will direct Midwest ISO and PJM to post on their open access same-time information system (OASIS) sites the policies/methodology for sharing of unused allocations, and any changes in the policies/methodology as they may develop.

53. Wisconsin Public Service raises a number of other “conforming changes” that it feels need resolution before the JOA can be implemented. However, it does not explain in any detail why these changes are important, much less necessary. Wisconsin Public Service has not explained why there would be a deleterious effect if these issues are not resolved immediately in the JOA and before the start of the Midwest ISO market this spring. Midwest ISO says that these are all Phase 1 proposed changes that need not be resolved before Phase 2 (market-to-market) is implemented. It says also that Midwest ISO and PJM have agreed to all of the changes, with the exception of the “credits” for new transmission facilities, and that those changes will be implemented as soon as software changes are in place. Midwest ISO says that it will form a group of reciprocal entities to address credits for new transmission facilities. Thus, we do not see any need to delay implementation of Phase 2 market-to-market coordination pending resolution of these issues. Further, it appears that the parties have already resolved the issues in principle, except the credits for new transmission facilities, and the process to deal with this issue is already in place.

54. The Commission has a few additional concerns about the JOA that were not raised in the comments filed. First, while the example provided in the market-to-market protocols is just an example, it is important that it be correct in order for it to add clarity to the process. However, the calculation given for the LMP of Generator 2 on Original Sheet No. 258 does not appear to match the calculations elsewhere for LMPs of generators in RTO B. In particular where the other LMP calculations for a generator in B are defined to be :

> LMP = System Marginal Price for B + (Gen DFAX) (RTO B Shadow Price)

The LMP for Generator B on Original Sheet 258 is defined to be:

> LMP = System Marginal Price for B + (Gen DFAX) (RTO A Shadow Price)

In the compliance filing ordered herein, the RTOs are directed to specify if this formula is correct, and to file a revision to the market-to-market protocols correcting it if it is not.

55. Next, the provision regarding day-ahead coordination on Original Sheet No. 252 that "under certain conditions, either RTO may request the Day-Ahead flow limit be raised above its Firm Flow entitlement," does not provide sufficient detail. The only condition provided is that the request must be made by 0700 EST. If there are any other restrictions on the RTOs in the circumstances under which they can request the day-ahead flow limits be raised, the conditions which restrict the requests must be laid out in the tariff. We direct Midwest ISO and PJM either to add those conditions to the tariff or to remove the language in question, if there are no further limitations.

56. As discussed above, we have conditioned our acceptance of the proposed amendments to the JOA on the RTOs providing clarification and/or further revision to address a number of issues. The RTOs are directed to submit a filing complying with these directives within 60 days of the date of this order.

2. <u>FTR Allocation and Auction Coordination</u>

a. <u>Proposal</u>

57. The December 30 Filing provides that the allocation of FTR products in each marketplace must recognize the flowgate entitlement that exists in adjacent markets. It states that the FTR allocation (or auction) model will contain the same level of detail for adjacent regions as the day-ahead market model and the real-time market model. Each RTO will allocate (or auction) FTRs to network and firm point-to-point transmission customers subject to a simultaneous feasibility test that determines the amount of

transmission capability that exists to support the FTRs. The simultaneous feasibility analysis for each RTO will model that RTO's flow entitlement on the RCFs in the adjacent region as the market flow limit that must be respected in the FTR allocation/auction processes. The RCFs in each RTO will be modeled in the simultaneous feasibility test at a capability value equal to the flowgate rating minus the flow entitlement for the adjacent market. Thus, the RTOs say, the FTR allocation across both their regions will recognize the reciprocal transmission utilization that exists for network and firm point-to-point transmission customers in both RTOs' markets.

b. <u>Comments</u>

58. Wisconsin Public Service asserts the filing fails to explain how the JOA will overcome the differences between the PJM and Midwest ISO FTR allocation processes. While the proposal calls for the same level of detail in the FTR allocation process, the use of different allocation processes for FTRs means that there is no assurance that the resulting calculations will be compatible. In addition, according to the presently laid out Midwest ISO FTR allocation schedule, FTR allocation periods of the two RTOs are not scheduled to coincide until June 1, 2006. This will be after Midwest ISO has gone through its first two allocation phases. Thus, Wisconsin Public Service states, FTR allocation/auction coordination between the two RTOs may not be able to start in a consistent and coordinated manner until June 2006. It states that the Commission should require PJM and Midwest ISO to clarify how the JOA will address FTR coordination prior to June 1, 2006.

c. <u>Answering Comments</u>

59. Midwest ISO says that the issue of further coordinating FTR allocations is important but appropriately addressed at a later date, as the parties move toward the joint and common market and gain some experience with the implementation of the market-to-market protocols. It says that short of doing a single allocation for the two RTOs under a joint and common market, the way to achieve coordination in the market-to-market phase is to have each RTO honor the other's firm flow entitlement when doing its FTR allocation. This, it says, allows each RTO to issue FTRs at the same time it recognizes impacts from the other RTO.

d. <u>Commission Discussion</u>

60. While more coordination in the FTR allocations would likely be ultimately beneficial for the market participants, we reiterate our ruling from the August 6, 2004 Order that Midwest ISO's annual FTR allocation follow PJM's schedule, from June 1 of

each year to May 31 of the following year.[26] At that time we asked for the parties to work together to assess when the allocation synchronization could occur, and the parties determined that the first year of coordinated allocation would occur on June 1, 2006.[27] The benefits of further coordination of FTR allocations, as well as the costs, will be assessed as part of the next step in planning the joint and common market, as discussed below. The Commission will be better able to assess the timeline for further coordination at that point.

C. Joint and Common Market Steps and Timeline

1. The RTOs' Proposal

61. The RTOs address the next-steps and timeline for achieving a joint and common market as required by the October 28, 2004 Order and the Transmission Rates Order by listing the benefits sought through a common market, articulating accomplishments of JOA Phase 1 implementation, describing anticipated outcomes of the proposed market-to-market provisions, and describing possible next stages of market development and coordination.

62. The RTOs state that the "next phase," after securing the benefits of the Phase 2 market-to-market coordination processes, is to establish a "functional common market" throughout the combined region. Features of the common market articulated by the RTOs include an "enhanced market portal"[28] that will serve as a single point of data entry and retrieval, imparting a single appearance to user interactions with either RTO so that transactions will be transparent across the common market encompassing the RTOs' footprints.

63. The RTOs explain that, as a foundation for the enhanced market portal, they will work to further develop common terminology, business rules, and data formats. The

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[26] *Midwest Independent Transmission System Operator, Inc*., 108 FERC ¶ 61,163 (August 6, 2004 Order) at P 194, *order on reh'g*, 109 FERC ¶ 61,157 (2004), *reh'g pending*.

[27] October 5, 2004 Compliance Filing of the Midwest Independent Transmission System Operator, Inc., in Docket Nos. ER04-104-106 and ER04-691-007.

[28] The term "enhanced market portal" appears to be used interchangeably with variations, such as "enhanced user interface" and "Phase 3 common market portal."

RTOs state that the currently differing rules are a byproduct of the different stages of evolution of the two markets, especially those resulting from Midwest ISO's multiple-control-area model and unique issues raised by its stakeholders. The RTOs say that the ability to transact across both RTOs through an enhanced market portal assumes that the RTOs have energy, ancillary services, and transmission service rules that, as much as practical, are in common. The RTOs state their intention to rationalize existing differences in rules, which may include maintaining some differences that do not interfere with the implementation of the common market, and that the common business environment needed to support the common market portal will require stakeholder and regulatory processes and approvals.

64. Replying to the Transmission Rates Order, the RTOs state that they "plan to initiate stakeholder processes in 2005 to resolve" the issues of integrating FTR allocation procedures and eliminating the pancaking of rates for ancillary services. The RTOs otherwise propose to allow six months after Midwest ISO energy market start-up for the new market-to-market operations phase to "stabilize" and then to take 18 months to identify rule changes necessary to create a common market and work through stakeholder and approval processes. After the regulatory approvals are complete, which they plan to achieve by March 1, 2007, the RTOs would design, develop, and implement information systems to create the common market portal, which the RTOs anticipate to be a six-month task. Assuming that Midwest ISO's energy market starts March 1, 2005, the RTOs project that a functional common market would start September 1, 2007.[29]

65. The RTOs anticipate that, once the enhanced market portal and common business rules are in place, the market will trend towards common pricing across both RTOs. The RTOs state their intention to assess the market's reaction at that time, evaluate the extent to which the objectives of price transparency and consistency across the combined region are achieved, and then balance those outcomes against the cost of further, systems-intensive changes and the incremental benefit expected of those changes.

66. The RTOs give examples of further coordination that may be pursued at that juncture, including: (1) full coordination of the day-ahead and real-time energy markets by performing joint security-constrained economic dispatch through an iterative approach, which would require a high level of integration and data transfer between the RTOs; and (2) implementing single day-ahead and single real-time markets across the combined footprint, which would require substantial cost to develop software for market clearing functions. The RTOs envision a period of twelve months after the

[29] An April 1, 2005 start to Midwest ISO energy market presumably would push the start date for a functional common market to October 1, 2007.

implementation of the common market to assess the need for, and costs and benefits of further changes like these.

67. The RTOs explain that much of the time allotted in this schedule is to allow stakeholders in the regions to help address the RTO's differing business rules. In addition, the RTOs warn that much technological work lies between concept and completions, even for options that do not necessitate a single market engine, and that each of these options is likely to require substantial investment in systems, practices, and personnel.

2. <u>Comments</u>

68. Wisconsin Electric protests the December 30 Filing as inconsistent with Commission directives and delaying, without justification, the timeline for implementing a joint and common market. Wisconsin Electric asserts that the coordination of FTR allocation processes and the elimination of pancaking of charges for ancillary services can and should be achieved well in advance of September 2007.

69. Wisconsin Electric argues that the RTOs' filing is "wholly inadequate," especially that their short statement that they "plan to initiate stakeholder processes in 2005 to resolve [the] issues" is an insufficient reply to the Commission's directive to provide a suitable timeline to fully integrate the allocation mechanisms for auction revenue rights (ARRs) and FTRs and to eliminate rate pancaking for ancillary services in the combined region.

70. In particular, Wisconsin Electric argues that complete integration of the ARR/FTR allocation mechanisms is a critical aspect of seams elimination in the combined region. Wisconsin Electric describes a fully integrated approach as one that would allow network integration transmission service customers of both RTOs to be treated in a comparable manner under either tariff with regard to network service designations and subsequent ARR/FTR designations. Wisconsin Electric asserts that these issues are an aspect of the desired joint and common market that require "immediate, unwavering attention" and asks the Commission to provide a firm date for integration of ARR/FTR mechanisms across the combined region.

71. Wisconsin Electric also asks the Commission to direct the RTOs to file a more instructive and definitive proposal to resolve the issues of ARR/FTR allocation methods and the elimination of rate pancaking for ancillary services, and attests that these two important issues can be resolved well in advance of September 2007. Wisconsin Electric notes that prompt implementation of a joint and common market was a critical requirement imposed by the Commission when it permitted ComEd to join PJM, rather than Midwest ISO, in the *Alliance Companies* Order. Wisconsin Electric points out that,

in that order, the Commission determined that nine months following the initiation of Midwest ISO's markets would be ample time to achieve a joint and common market, and argues that nothing has changed so much as to warrant the twenty-nine month delay following market start-up proposed by the RTOs.

3. Answering Comments

72. In its answer, Midwest ISO acknowledges the importance of the issues raised by Wisconsin Electric, but states that they are not essential to the implementation of Phase 2 coordination and insists that the December 30 Filing meets the Commission's requirements. Midwest ISO reiterates its view that it is important to take adequate time to test and validate Phase 2 coordination before moving to the development of the joint and common market. It states that the RTOs intend to initiate a stakeholder process to address Wisconsin Electric's issues, but only after Midwest ISO's market is launched and both markets have stabilized under the market-to-market protocols. It asserts that implementation experience will assist in resolving the ARR/FTR and rate pancaking issues.

4. Commission Discussion

73. The December 30 Filing provides a general explanation of the process and timeline that the RTOs intend to use to move beyond market-to-market coordination and toward the joint and common market referenced by the JOA and prior Commission orders. In requiring the RTOs to include a detailed timeline of the steps they will take to achieve the joint and common market, we had anticipated more specificity that would have allowed us to evaluate and establish priorities for individual elements of the joint and common market and timelines in which those elements can and should be achieved. However, we understand that the RTOs and affected parties are immersed in the tasks necessary to start the Midwest ISO market. In addition, this will be the first peak summer season that PJM will experience with both AEP and ComEd integrated into its footprint.

74. We agree with the RTOs that future market development will benefit from allowing some time for both the Midwest ISO market itself and the market-to-market coordination protocols approved herein to stabilize following their implementation. However, we believe that meeting schedules and plans must be laid out in the near future in order to avoid unnecessary delays following this stabilization period. We also agree with Wisconsin Electric that it may be possible to resolve some matters before the implementation of an enhanced market portal is complete. We believe that certain elements of the joint and common market may be achievable on their own and that it may be possible and beneficial to implement such elements sooner rather than later.

75. To that end, we will allow the RTOs to focus on implementing the market-to-market protocols for several months, but require the RTOs to redouble their efforts immediately thereafter to complete the next steps necessary to achieve a joint and common market. Anticipating that the RTOs can soon set dates for the stakeholder meetings they referenced, we will direct the RTOs to lay out a schedule of meeting dates, in its next progress report, for the stakeholder process it envisions and to convene the first meeting between 60 and 90 days following the start of the Midwest ISO market. With market-to-market coordination starting April 1, 2004, the RTOs will have at least two months to stabilize procedures before the first stakeholder meeting. Proposed for June, the first meeting should come late enough to be informed by the market initiation experience and early enough to precede peak weather season. In their progress report due on or about June 28th, we will require the RTOs to lay out a schedule that, barring significant weather, reliability or market crises, facilitates the filing, on October 31, 2005, of a more specific plan, described below, for continuing development of a joint and common market.

76. The Commission directs the RTOs to identify and provide narrative description of each specific element of a joint and common market, and the tasks necessary for them to complete, the impediments for them to overcome, and the resulting changes necessary to their tariffs, rules, systems, and procedures to accomplish the enhanced market portal and other elements necessary to commencement of common market operations and ultimately a joint and common market. The RTOs are to provide, for each element, specific timelines for accomplishing the tasks associated with each change that they identify as necessary to achieve that element and an evaluation of the expected costs and benefits associated with achieving the element. The RTOs shall file this concrete plan and timeline with the Commission on or by October 31, 2005. The RTOs are urged to identify and proceed with development and implementation of individual elements of the joint and common market that are feasible and beneficial to implement on an individual basis as quickly as possible.

V. <u>Conclusion</u>

77. After review and analysis of the proposed revisions to the JOA, we conclude that they represent an important achievement in seams resolution. Accordingly, we will accept the proposed revisions, subject to the modification and conditions described above. In addition, we will require the RTOs to file a concrete plan and timeline for achieving the elements necessary to achieve the enhanced market portal and otherwise commence common market operations as well as to ultimately achieve a joint and common market. Further, we ask the RTOs to identify and explain in the timeline those elements which may bring net benefits to the market earlier, and encourage the RTOs to develop those elements as early as possible.

<u>The Commission orders</u>:

(A) Midwest ISO's and PJM's proposed revisions and additions to the Joint Operating Agreement are hereby conditionally accepted for filing, as discussed in the body of this order, with the revisions and additions providing for Phase 2 of the JOA to become effective on the date that Midwest ISO commences its energy market.

(B) Midwest ISO and PJM are hereby required to make a compliance filing addressing the clarifications and further revisions pertaining to the Phase 2 market-to-market protocols, as discussed in the body of this order, within 60 days of the date of this order.

(C) Midwest ISO and PJM are hereby required to file a concrete plan and timeline, on or by October 31, 2005, that provides substantive detail and narrative, as discussed in the body of this order, of the elements necessary to comprise a common market, the impediments they anticipate having to overcome and the necessary tasks they expect to accomplish in order to commence common market operations.

(D) Midwest ISO and PJM are hereby required to include in their progress report due on or about June 28, 2005, a schedule of stakeholder meetings and other activities necessary to ensure the development and filing of the above concrete plan and timeline by October 31, 2005, as discussed in the body of this order.

(E) Midwest ISO's requests for waiver of the service requirements set forth at Rule 2010 of the Commission's Rules and Regulations, 18 C.F.R. § 385.2010 (2004), are hereby granted.

(F) Midwest ISO's January 28, 2005 motion in Docket No. ER04-375-018, to change the requested effective date of tariff sheets in the December 30 Filing, including those addressing the commencement of Phase 2, to coincide with the start of financially binding energy market operations, is hereby granted.

By the Commission.

(S E A L)

Linda Mitry,
Deputy Secretary.