108 FERC ¶ 61,235
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. ER02-2595-000 and ER02-2595-003

ORDER ON PAPER HEARING AND COMPLIANCE FILING

(Issued September 16, 2004)

**Introduction**

1. In this order we consider the submission of information in a "paper hearing" which was initiated by the Commission in *Midwest Independent Transmission System Operator, Inc.*, 101 FERC ¶ 61,221 (2002) (November 22 Order), *reh'g denied*, 103 FERC ¶ 61,035 (2003) (Rehearing Order). Here, we approve the billing determinants for the rates applicable to services in Schedules 16 and 17 of the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) Open Access Transmission Tariff (OATT) and reject the proposed exit fee allocation and require Midwest ISO to negotiate the exit fee with the withdrawing transmission owner prior to filing the exit fee with the Commission. We also accept in part and reject in part the compliance filing submitted by Midwest ISO and order an additional compliance filing consistent with the discussion below. This order benefits customers by ensuring appropriate unbundled market-related charges that align cost responsibility with the benefits received.

**Background**

**November 22 Order and Compliance Filing**

2. On September 24, 2002, Midwest ISO filed proposed Schedules 16 and 17, the cost recovery mechanisms for Midwest ISO's provision of Financial Transmission Rights (FTR) Administrative Service (FTR Service) and Energy Market Support Administrative Service (Energy Market Service), respectively.[1]

3. The November 22 Order accepted the proposed Schedules 16 and 17 for filing, suspended them, and made them effective November 25, 2002, subject to refund. The Commission noted that the record did not contain sufficient information to resolve the issues concerning the proposed billing determinants. A "paper hearing" was ordered where, among other things, the parties were directed to address the benefits received and the degree of cost causation generated for these services.[2] The Commission also included the issue of exit fee allocation in the "paper hearing". In addition, Midwest ISO was ordered to make a compliance filing that: (1) "delete[s] the language that makes payment of the exit fee a condition precedent to withdrawal from Midwest ISO"[3] and (2) details the cost allocations for its formula rate consistent with the Commission's policy and requirements.[4]

4. On January 6, 2003, Midwest ISO made a compliance filing that removed the language requiring payment of the exit fee as a condition precedent to withdrawing from Midwest ISO. The compliance filing also provided greater specificity in the formula rates.

[1] Schedule 16 provides for a deferral of costs related to the development and implementation of the system and processes required to administer FTRs. Those deferred costs and the costs related to the ongoing administration of FTRs will be collected from markets participants that own FTRs. Schedule 17 provides for a deferral of start-up costs related to the establishment of energy markets and recovery of such deferred costs as well as the ongoing operational costs of providing Energy Markets Service.

[2] November 22 Order, 101 FERC ¶ 61,221 at P 44.

[3] *Id.* at P 52.

[4] *Id.* at P 64.

**Briefs, Protests and Other Pleadings**

5. The November 22 Order stated that: "parties may submit to the Commission additional arguments and evidence as outlined in the body of this order, 60 days from the issuance of this order. Replies may be made 15 days thereafter."[5]

6. The Attorney General of the State of Minnesota (AGM) and Oklahoma Gas & Electric Company (OG&E) filed untimely motions to intervene with protests. The Missouri Public Service Commission (Missouri Commission) filed an untimely motion to intervene with comments. FirstEnergy Corporation (FirstEnergy) filed an untimely motion to intervene.

7. The Midwest ISO Transmission Owners (Midwest ISO TOs)[6], FirstEnergy, Great River Energy (GR Energy) and Dairyland Power Cooperative (Dairyland), Wisconsin Electric Power Company (WEP), Minnesota Department of Commerce and Indiana Office of Utility Consumer Counselor (MN DOC/IN UCC), and Public Service Commission of Kentucky (Kentucky Commission) filed initial comments/briefs.

8. Trial Staff, Missouri Commission, Midwest ISO, Wisconsin Public Power Inc. (WPPI), Public Utilities Commission of Ohio (Ohio Commission) and Kentucky Commission filed reply comments/briefs.

[5] *Id.* at Ordering Para. (E).

[6] The Midwest ISO TOs, for the purposes of the paper hearing, are: Ameren Services Company (for Union Electric Company and Central Illinois Public Service Company); Alliant Energy Corporate Services, Inc. as agent for IES Utilities Inc. and Interstate Power Company; American Transmission Company LLC; Aquila (for UtiliCorp United Inc.); Central Illinois Light Company; City Water, Light & Power (Springfield, IL); Hoosier Energy Rural Electric Cooperative, Inc., Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company, LG&E Corporation (for Louisville Gas and Electric Co. and Kentucky Utilities Co.); Lincoln Electric System; Minnesota Power, Inc. (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northwestern Wisconsin Electric Power Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; and Wabash Valley Power Association, Inc.

9. The Midwest ISO TOs[7] and Dairyland filed protests to the compliance filing. Midwest ISO filed an answer to the protests.

10. We will discuss these filings in more detail below.

## Discussion

### Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2004), we will grant the untimely motions to intervene. The motions express interests not adequately represented by another party; however, since these parties have filed the untimely motions very close to the date that the Commission issued its decision,[8] these parties must accept the record as it stands so as not to place additional burdens on other parties.[9]

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2004), each timely, unopposed notice to intervene and motion to intervene serve to make the entities that filed the motions parties to the compliance proceeding in Docket No. ER02-2595-003.

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[7] The Midwest ISO TOs, for the purposes of the compliance filing, also includes Cinergy Services, Inc. (for Cincinnati Gas & Electric Company, PSI Energy, Inc., and Union Light Heat & Power Company).

[8] OG&E and FirstEnergy filed their late motions two days before the November 22 Order was issued.

[9] It is Commission policy that parties seeking to intervene after an order has been issued have a heavy burden to show good cause to support their late intervention. *See, e.g.*, Garnet Energy LLC, 99 FERC ¶ 61,165 (2002). The instant proceeding represents an exception to this policy. Ordinarily the AGM's and the Missouri Commission's late motions to intervene would be denied because their motions provide no support for the late intervention requests. However, in this case, the November 22 Order contemplated that additional evidentiary filings would be made in the paper hearing that addressed, among other things, "any issue that they (the parties) believe would assist the Commission in making the policy decision concerning the appropriate billing determinants. . ." *See,* November 22 Order, 101 FERC ¶ 61,221 at P 44. Thus, we find that the late interventions will not cause any undue burden on the parties.

13. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.213(a)(2)(2004), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept Midwest ISO's answer because it aids in our understanding of the issues.

## Paper Hearing

### Schedule 16 Billing Determinants

#### Midwest ISO Proposal

14. The proposed Schedule 16 is designed to recover the costs associated with implementing and administering FTR Service from FTR owners based on their proportionate share of FTR capacity (MW) in each hour of the month.[10] The proposed rate design, similar to the load ratio share for transmission rates, requires FTR owners that benefit from congestion hedging to pay their share of the costs to provide the hedge.[11] Midwest ISO identifies the five primary activities that it undertakes to provide FTR Service. These activities are: (1) simultaneous feasibility analysis;[12] (2) administration of FTRs and revenue distribution; (3) administration of FTRs through

[10] FTRs are financial instruments entitling the owner of the FTR to receive compensation for or requiring the FTR owner to pay for certain congestion related transmission charges that arise when the Transmission System is congested and differences in Locational Marginal Prices (LMP) result from the redispatch of resources out of economic merit order to relieve that congestion.

[11] The cost of congestion is calculated as the difference of the marginal congestion component of LMP at the sink and the marginal congestion component of LMP at the source. The compensation received from FTRs hedge this cost of congestion.

[12] Midwest ISO performs "simultaneous feasibility" analyses to determine the total combination of FTRs that can be outstanding and accommodated by the Transmission System at a given point in time to include normal system conditions and defined contingencies. The Simultaneous Feasibility Test (SFT) will be performed any time that Midwest ISO awards a new or reconfigured FTR. The SFT uses settings that are consistent with the average state of Midwest ISO transmission system for the time period that the FTRs are scheduled. Once all data has been entered into the software program, the software model then determines whether or not the power flow from the set of nominated FTR obligations and FTR options violates any monitored element with all lines in service. The software model also tests whether the nominated set of FTRs is feasible in each of the defined contingencies.

allocation, assignment, auction or other process accepted by the Commission;[13] (4) support of Midwest ISO's on-line, internet based FTR tool to assist trading of FTRs; and (5) coordination of FTR bilateral trading.[14]

15. Midwest ISO states that the overall design of the rate for FTR Service, which was submitted to stakeholders for comment prior to filing, essentially mirrors PJM's FTR Service charge.[15] Midwest ISO identifies the issues it considers in order to determine whether to further unbundle charges in addition to the one charge proposed here. These considerations are whether: (1) the costs of the unbundled service is significant and readily identifiable; (2) the proposed service's customer base is identifiable; and (3) the costs are different from those incurred on behalf of the customer base for other services, and the cost drivers are different from the cost drivers of other services. In addition, Midwest ISO states that the unbundling needs to be practical from an implementation perspective. Midwest ISO contends that FTR Service and the proposed charge meet these criteria. Furthermore, Midwest ISO argues that parties that use and benefit from FTR Service should pay for the service, and all load should not be assessed these charges under Schedule 10 for FTR Service regardless of whether they used or benefited from FTR Service.[16]

16. Midwest ISO further explains that in developing its charge for FTR Service it was mindful of avoiding improper economic signals that would have unwanted adverse effects on the behavior of market participants such as encouraging or discouraging certain

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[13] Midwest ISO annually allocates FTRs to customers of Network Integration Transmission Service, Point-to-Point Transmission Service and certain Grandfathered Agreements to reflect their existing entitlements to the use of the transmission system operated by Midwest ISO. Midwest ISO also conducts annual and monthly auctions to sell FTRs representing the remaining transfer capacity in the footprint and to facilitate transfer of FTRs between market participants.

[14] Among other things, Midwest ISO certifies that the seller owns the FTRs being sold and the buyer meets certain creditworthiness standards prior to transferring ownership of the FTRs.

[15] *See*, Exhibit No. MISO-7 at p 5. *See also*, PJM Interconnection, L.L.C. 92 FERC ¶ 61,144 (2000).

[16] Schedule 10 contains the ISO Cost Adder which, prior to the filing of Schedules 16 and 17, collected all of Midwest ISO's costs

transactions if such transactions could avoid (or were over-proportionately burdened by) ISO administrative charges.[17] Midwest ISO relies on an earlier Commission order where the Commission stated:

> [t]he selection of how costs are recovered, *i.e.,* rate design, can have significant market implications. For example, customer charges can discourage small participants [and] per-transactions charges can chill needed trading…[18]

**Initial Comments/Briefs**

17. Several commentors, including the Midwest ISO TOs, state that costs should be assigned as narrowly as possible, *i.e.*, to those that use and benefit from the service consistent with the ratemaking principle of cost causation. The Midwest ISO TOs assert that the Commission has followed cost causation principles in order to assess the administrative charges of regional transmission organizations.[19] The Midwest ISO TOs argue that a transaction charge should be assessed directly on market participants that use the services.[20] According to the Midwest ISO TOs, the costs associated with FTR bilateral trading and FTR auctions should be recovered from the market participants that

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[17] *See*, Exhibit No. MISO-7 at 8.

[18] Midwest ISO *cites* ISO New England, 89 FERC ¶ 61,339 at 62,019 (1999), *reh'g denied*, 91 FERC ¶61,016 (2000).

[19] See Midwest ISO TOs Brief at 8 *citing,* ISO New England, Inc., 85 FERC ¶ 61,453 (1998); Central Hudson Gas & Electric Corporation 86 FERC ¶ 61,062 (1999), *reh'g denied*, 104 FERC ¶ 61,225 (2003); and PJM Interconnection, L.L.C., 92 FERC ¶ 61,114 (2000) *order approving settlement*.

[20] The Midwest ISO TOs *cite* Automated Power Exchange, 84 FERC ¶ 61,020 (1998); California Power Exchange Corporation, 87 FERC ¶ 61,203 (1999); and ISO New England, Inc., 96 FERC ¶ 61,261 (2001).

choose to buy or sell FTRs. The costs of these activities, the Midwest ISO TOs maintain, would be determined through a cost study that would determine a monthly transaction fee.[21]

18. Kentucky Commission agrees with the Midwest ISO TOs and claims that Midwest ISO does not provide open access transmission service to bundled retail customers; nor do bundled retail customers benefit from the Midwest ISO OATT service provided to bundled load serving entities.[22] Kentucky Commission argues that Kentucky's bundled retail load will not participate in the market and as a result will not cause Midwest ISO to incur costs.

19. Missouri Commission argues that Midwest ISO should unbundle the costs related to FTR Service in Schedule 16[23] into four charges so that benefits are matched with the costs of FTR Service. Missouri Commission asserts that this unbundling could be accomplished by: (1) allocating FTRs based on the level of protection provided by the FTRs (*e.g.*, the dollars of congestion costs forgiven); (2) developing a charge for operating the auctions (assessed to customers on the basis of congestion costs returned or MWs of FTRs); (3) developing a charge for coordinating bilateral trade of FTRs

[21] Midwest ISO TOs' witness Mr. Heintz, states that as part of the unbundling study, Midwest ISO should determine the level of its costs that are associated with FTR auctions and trading support in order to set a transaction fee per MW of FTRs bought or sold through trade or auction. If Midwest ISO has not completed the unbundling study prior to the commencement of FTR Service, Midwest ISO TOs argue that the Commission should institute a small "placeholder" percentage fee on FTR sales/ purchases/transfers until the actual fee is calculated as a result of the study. *See* Exhibit No. MISO TOs -1 at 18.

[22] In contrast, MN DOC and IN UCC acknowledge that bundled retail load may use some, but not all, of the services and recommends unbundling the charge so that bundled retail load does not have to pay for Midwest ISO activities that they did not cause.

[23] Great River and Dairyland state that adding a charge for FTR Service to the existing rates constitutes rate pancaking because the existing agreements already provide the same level of Schedule 16 service.

(assessed to customers via a subscriber fee for Midwest ISO's internet-based FTR trading tool); and (4) developing a settlement charge (assessed via a customer charge, as these costs tend not to vary with usage).[24]

20. MN DOC and IN UCC propose that FTR reallocation and FTR auction costs be tracked separately (via a cost pool, spreadsheet or subaccount) so that the proposed rates can be unbundled and customers that benefit from the services pay the charges. MN DOC and IN UCC state that the remaining FTR service costs, which MN DOC and IN UCC estimate to be less than half of the FTR service costs, may be appropriately allocated to all users of the transmission system. MN DOC and IN UCC assert that native load retail customers in states like Minnesota and Indiana do not require all the services and therefore do not benefit as much as other customers do. For example, they point out that open access states require continuous reallocation of FTRs when a customer changes suppliers.

**Reply Comments/Briefs**

21. Missouri Commission objects to the Midwest ISO TOs' proposal for a transaction-based charge for Schedule 16. It argues that this proposed transaction-based charge is not value-based, because neither the costs of determining FTRs available for allocation nor the settlement costs associated with the FTRs have been allocated. It asserts that the proposal assumes that all FTRs sold or traded will be equivalent on a MW basis which may not be true for point-to-point FTRs.[25] Missouri Commission points out that Midwest ISO will also offer flowgate FTRs and, it argues, that may be a better basis for determining a transaction charge for auctioned FTRs. Missouri Commission asserts that using FTR MWs awarded in the auction on fully subscribed flowgates would eliminate any bias in favor of bidding on point-to-point FTRs over flowgate FTRs. According to Kentucky Commission, the costs associated with FTR Service that are not unbundled should be allocated to all users of the transmission system because these users benefit from the conversion of firm service to FTRs.

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[24] Since Midwest ISO must have load profiles for each Load Serving Entity (LSE) and must balance these profiles with metered loads to properly perform settlements, Missouri Commission proposes that load profiling be offered separately from Schedules 16 and 17 and the charge be based on the number of load profiles required for each LSE.

[25] Missouri Commission states that a point-to-point FTR can encompass multiple flowgates where the FTRs are fully subscribed; *i.e.,* where market participants in aggregate believe there will be congestion in the day-ahead markets and are willing to pay up-front dollars to hedge against that congestion.

22. Ohio Commission maintains that bundled and unbundled customers will benefit from the creation of the FTR services. It points out that the creation of the markets will enhance wholesale competition in the entire Midwest ISO region, not just those areas that have elected to endorse retail competition; therefore, Ohio Commission argues that the commentor proposals for a distinction of bundled versus unbundled retail customers is not appropriate. Ohio Commission argues that the Commission should consider the rate impacts on retail access states so that they are not unreasonably burdened to the point of hindering retail access. Midwest ISO's filing does not contain the information necessary to determine the burden on Ohio's ratepayers; therefore, Ohio Commission recommends postponing further unbundling until Midwest ISO has operational experience with these services.

23. WPPI states that most commentors' recommendations are designed to shift as many of the charges to a small group of "users" of the services so they can avoid the charges. If the bulk of the load in the footprint can avoid the cost of implementing and administering FTRs, then the cost of the market will be so high that it will not be cost effective. WPPI argues that the proposals of most of the commentors would place perverse incentives on Midwest ISO with regard to the method for assignment of FTRs and doom the market. WPPI asserts that if the Commission sees merit in the initial commentors' requests for exemption and further unbundling of FTR costs, then the Commission should reconsider whether the LMP-based energy markets and the associated FTR hedging mechanism are worth pursuing, because the cost is high and there may be a more cost-effective path to achieve its pro-competitive and pro-consumer goals.

24. In its reply brief, Midwest ISO argues that transaction fees which were proposed by many contesting parties result in more cost than benefit. According to Midwest ISO, transaction fees introduce greater complexity into operations and therefore transaction fees will increase costs. Midwest ISO elaborates that under some of the proposals, transaction fees would have to be recalculated monthly and the parties to each transaction would have to be identified separately and billed on a unit of activity basis; thus requiring greater accounting and settlement resources than currently planned by Midwest ISO. Moreover, Midwest ISO states that only a small portion of FTR Service costs, if any at all, would likely be driven by the number of transactions and determining the amount of such costs without operational experience would be difficult and the resulting charges would run the risk of discouraging FTR trading and participation by smaller entities and new market participants.[26]

[26] *See* Exhibit No. MISO-7 at 12.

**Commission Determination**

25. We find that Midwest ISO's proposed unbundling of costs associated with FTR Service is reasonable. Under Midwest ISO's proposal the costs of FTR Service are isolated and assessed to the beneficiaries of FTR Service on a basis that is proportional to amount of FTRs held. While further refinement to the unbundling of FTR Service costs may be possible after Midwest ISO gains operational experience, we believe that Midwest ISO's proposal is consistent with the precedent cited by Midwest ISO TOs requiring that ISO funding mechanisms be assessed to the beneficiaries of the service.[27] As FTRs replace physical rights, it is reasonable to charge for the FTR system based on a similar mechanism to that used for transmission service rates, *i.e.*, the customer is charged based on the amount of service it has rights to. As to transaction charges for the trading of FTRs, the current system does not charge for the flexible use of the system, *e.g.*, using an alternative point-to-point path or alternative designated network resource. The Midwest ISO TOs and others arguing for a transaction charge have not demonstrated the nexus between FTR trading and the cost of the system to administer FTRs, nor is there any experience in Midwest ISO to support such a proposal, as noted by the Ohio Commission. Moreover, the proposal was based on PJM's charge for FTR Service, which will facilitate the goal of a common market between Midwest ISO and PJM. The proposal also addresses our concerns regarding market implementation of rate design.[28]

26. Contesting parties suggest further unbundling is necessary of the costs recovered under Schedule 16 to assess certain costs via transaction fees, subscription fees and customer charges to the customers that use or benefit from Midwest ISO's activities. While the Midwest ISO TOs are correct that the Commission has not forbidden transaction-based charges for ISOs,[29] the Commission has also expressed concern about the chilling effect on the market that can occur when those transaction-based charges are not properly supported or are not the result of a settlement.[30] There is no basis in the record to establish a transaction-based charge for Schedule 16, including Midwest ISO

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[27] The Midwest ISO TOs *cited* ISO New England, Inc., 85 FERC ¶ 61,453 (1998); Central Hudson Gas & Electric Corporation 86 FERC ¶ 61,062 (1999), *reh'g denied*, 104 FERC ¶ 61,225 (2003); and PJM Interconnection, L.L.C., 92 FERC ¶ 61,114 (2000) *order approving settlement*.

[28] *See* ISO New England, 89 FERC ¶ 61,339 at 62,019 (1999).

[29] *See* ISO New England, Inc., 96 FERC ¶ 61,261 (2001) (Order approving uncontested settlement), ISO New England, Inc., 106 FERC ¶ 61,294 (2004) (Order accepting transaction-based charges targeted at virtual traders who stated they could accept the outcome) and PJM Interconnection, LLC, 107 FERC ¶ 61,007 (2004) (Order approving compromise).

[30] *See* ISO New England, 89 FERC ¶ 61,339 at 62,019 (1999).

TOs' suggestion of a "placeholder" transaction-based rate.[31] We expect that as Midwest ISO gains actual operating experience, the stakeholders can reexamine the appropriateness of further unbundling Schedule 16 costs.[32]

27. We are also not persuaded by the argument that a transmission owner taking service for bundled retail load should pay a different rate under Schedule 16 than unbundled retail load. The change from a physical rights model, under which Midwest ISO currently operates, to a financial rights model impacts all customers under the tariff. All customers under the tariff will have access to the benefits of the enhanced marketplace and improved system reliability and efficiency, including bundled retail load through the member transmission owners that serve them. All customers who hold FTRs to hedge against congestion charges benefit from having FTRs available and should pay for their provision.

28. An order concerning Midwest ISO's Grandfathered Agreements (GFAs)is being issued concurrently.[33] That order explains that GFAs that receive a financial hedge against congestion should pay the Schedule 16 charges for the benefit of the hedge against congestion regardless of whether they hold the FTRs or Midwest ISO holds the FTRs for them. We also determine that GFAs that do not receive a hedge against congestion or those GFAs that are not subject to congestion in the first instance should not pay the charge in Schedule 16. In that order Midwest ISO will be required to submit a compliance filing clarifying Schedule 16 to require those GFAs for which Midwest ISO holds the FTRs (*i.e.,* Option B GFAs) be assessed the charge under Schedule 16.[34] With

[31] The Midwest ISO TO's proposal for a "placeholder" rate is unclear as to whether the 1 percent fee would apply to both the sale and purchase for a total of 2 percent or whether it would apply once to the "transfer." Additionally, if the 1percent fee applied to both the sale and the purchase for a total of 2 percent, it is unclear from the record whether the cap would be applied individually for a total cap of $2.00/Mwh or on the entire transaction for a total cap of $1.00/Mwh. The proposal also fails to address the issue of administering the transaction-based charge. See California Independent System Operator, 103 FERC ¶ 61,114 (2003) (Commission rejects alternative unbundling proposal because, at the very least, the proposal was incomplete).

[32] Since the flowgate FTRs are not even offered at this time, we believe that Missouri Commission's concern regarding point-to-point FTR versus flowgate FTR is premature.

[33] We will refer to that order as the "GFA Order."

[34] We note that section 38.8.3.a of the proposed Energy Markets Tariff requires Option B GFAs to pay the charges in Schedule 16. However, Schedule 16 is not as clear on the treatment of Option B GFAs since the proposed billing determinant for Schedule 16 is "the total amount of FTR volume for all FTR Holders" which seems to exclude the Option B GFAs because they are not owners of FTRs.

this modification, we find that the proposed billing determinants properly reflect the assessment of the charges to GFAs as determined in the concurrent order.

**Schedule 17 Billing Determinants**

**Midwest ISO Proposal**

29. Midwest ISO proposes Schedule 17, Energy Market Service, in order to recover the costs it incurs to implement and administer the energy markets, including deferred startup costs. The energy markets consist of the day-ahead energy market and the real-time energy market, through which market participants supply offers to sell and bids to buy energy.[35] Midwest ISO identifies six main activities it undertakes in providing Energy Market Service as: (1) market modeling and scheduling functions, (2) market bidding support, (3) LMP support, (4) market settlements and billing, (5) market monitoring functions, and (6) enabling the least-cost, security-constrained commitment and dispatch of generating resources to serve load in the Control Areas within its footprint while establishing a spot energy market.

30. Midwest ISO patterned its proposal after PJM's Energy Market Service charge.[36] The billing determinants for Energy Market Service proposed by Midwest ISO are the sum of all MWh injections into the Transmission System, MWh extractions from the Transmission System and all virtual bids or virtual offers, settled in the Day-ahead market that don't actually inject or extract from the Transmission System.[37] However, Midwest ISO explains that it did not include two compromises achieved in the settlement of PJM's rate. Specifically, Midwest ISO states that it did not reflect the negotiated two-

[35] Midwest ISO defines a security-constrained economic solution; which translates into LMP at various locations within the Midwest ISO footprint. LMP is the market clearing price for energy at a given location in the Transmission Provider Region which is equivalent to the cost of supplying the next increment of load at that location taking into account the physical limitations of the Transmission Provider Region.

[36] *See*, Exhibit No. MISO-7 at 21.

[37] Through the market participants' abilities to arbitrage between the day-ahead and real-time market, Midwest ISO argues that each of the two markets will play an important role in making operations of the other market more efficient. *See*, Exhibit No. MISO-3 at 8.

year phase-in for generators but it did include wheel-through transactions, whereas PJM did not.[38] Mr. Pfeifenberger, witness for Midwest ISO, states that PJM's two-year phase-in for the assessment of the charge to generators is not needed for Midwest ISO, because Midwest ISO's energy markets will not commence for awhile (thereby giving generators time to adjust to the new charge). Mr. Pfeifenberger also states that wheeling-through transactions should be assessed the charge because they will benefit from Midwest ISO's energy market by utilizing the transmission and congestion management system just as import and export transactions in the spot market do.

31. Midwest ISO states that it is reasonable to assess the Energy Market Service charge to both generators and load because both will benefit from the energy markets. Mr. Pfeifenberger states, Midwest ISO is responsible for the coordination, congestion management and scheduling associated with all energy transactions including spot market transactions and bilateral transactions.[39] Mr. Pfeifenberger continues that Midwest ISO's real-time and day-ahead markets will be the primary congestion management tool; that is central to the efficient operation of all energy markets. Mr. Pfeifenberger claims that well functioning, liquid and efficiently priced real-time and day-ahead energy markets will likely become the central reference point for the efficient price setting of all energy transactions, including all long-term and bilateral transactions.[40] Mr. Pfeifenberger concludes that the recovery of Energy Market Service costs from all generation injections and load extractions from Midwest ISO's Transmission System is appropriate because the generators and load benefit from the service.

32. Midwest ISO states that it is unnecessary and administratively infeasible to further unbundle costs associated with the development and administration of the energy markets. According to Midwest ISO, it is unnecessary to further unbundle the Schedule 17 costs between day-ahead and real-time markets because entities injecting and extracting energy from the transmission system will benefit from both the day-ahead and real-time markets since each market helps to make the other more efficient.[41] Accordingly, as a result of the benefit from both markets, parties should be charged for the cost of both markets. Mr. Monroe also contends that in addition to the need to allocate joint capital costs, further unbundling would require the assignment and

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[38] At the time of Midwest ISO's filing, PJM also did not assess a charge to energy market transactions that do not result in actual physical injection and extraction of MWh in real time (*i.e.*, virtual trades). PJM has since modified its administrative charges to assess virtual traders for a portion of the costs associated with their settled and unsettled bids and offers.

[39] *See*, Exhibit No. MISO-7, p 17.

[40] *Id*., p 18.

[41] S*ee*, Exhibit No. MISO-3 at p 8.

allocation of personnel associated with the administration of day-ahead market and real-time market. Midwest ISO explains that such refinement would be very difficult and potentially arbitrary at this time.[42] Midwest ISO warns that further unbundling would risk distorting participation in the markets by overcharging for one market (*e.g.,* real-time market) relative to the other market (*e.g.,* day-ahead market).

**Initial Comments/Briefs**

33. Numerous entities argue that only those entities buying or selling energy through the day-ahead and real-time markets should pay for them.[43] In general, they argue that self-scheduling entities, those with bilateral contracts, arranged their purchases and sales without a centralized market and, therefore, should not have to bear the cost of the market structure. Midwest ISO TOs argue that those entities that self-schedule their own generation to serve their own loads directly rely on only a few of the Midwest ISO Schedule 17 activities. For example, Midwest ISO TOs state that "bidding support" and "market settlement or billing support" are not needed for self-scheduling entities and "market monitoring" is not needed as much as for spot market purchasers.[44] The Midwest ISO TOs propose unbundling the Schedule 17 costs into three groups (1) scheduling costs presently recovered under Schedule 17 would be recovered in Schedule 10, (2) a portion of Schedule 17 costs be recovered through a transactional charge on settled trades in the spot energy market and (3) the remainder of the costs presently in Schedule 17 would be recovered as proposed by Midwest ISO on generation and load.[45]

34. FirstEnergy states that charging bilateral contracts for the markets may make the transaction uneconomic or may lead to the inability to recover the Schedule 17 charge from the purchaser, since it is not contained in the contract. It adds that this additional

[42] For example, Schedule 17 activities are common to the administration of day-ahead and real-time markets and could not easily be separated.

[43] Midwest ISO TOs, Kentucky Commission, FirstEnergy, Great River, Dairyland, AGM, MN DOC and INUCC.

[44] Midwest ISO TOs state that the electricity costs of self-scheduling entities "are fixed by long-term contract or by the embedded costs of their installed generation, rather than by the spot market that is the primary focus of the market monitor."

[45] Midwest ISO TOs recommend the Commission order Midwest ISO to perform an unbundling cost study to determine the portion of Schedule 17 costs that should be assessed in a transaction-based charge and should demonstrate and justify the assignment of costs between Schedule 10 and the two new schedules.

charge creates inefficiencies because it encourages purchases in the energy markets even though there may be more efficient bilateral trades. FirstEnergy argues that the Standard Market Design proposed rulemaking[46] encouraged entities to rely primarily on contracts for energy supply and only secondarily on spot markets. FirstEnergy also alleges that charging the cost of energy markets to self-schedulers limits the prospects of achieving appreciable demand-side response because load-serving entities offer demand-side customers a fixed price, in advance, for agreeing to curtail load and these extra costs come at the expense of sellers' economic ability to offer attractive prices for demand-side customers.[47]

35. MN DOC and INUCC argue that the self-scheduling LSEs should not be charged the full Schedule 17 charge or at least they should not be charged twice (*i.e.*, once for generation and again for load).[48] They support a transaction-based charge. They are concerned that accepting the billing determinant, as proposed, will permit a cost shift from wholesale customers and marketers that use this service to native retail load in states that do not have open access contrary to the Commission’s statements in SMD that cost shifts will not occur.

36. Great River and Dairyland propose that the Schedule 17 billing determinants exclude long-term bilateral contracts and self-supplied generation. Alternatively, they propose that the portion of the services that self-scheduling entities do not use such as settlement and billing be billed on a transaction basis and that the remainder of the costs be assessed to all load. Great River and Dairyland also object to the marketers escaping from the Schedule 17 charges since the charge is largely based on injections and withdrawals from the transmission system which marketers do not have to do.

37. Missouri Commission proposes that the costs for Energy Market Service should be further unbundled and assessed via four charges: (1) scheduling, assessed according to the amount of MWs scheduled by generators, load and virtual traders; (2) dispatch and pricing, assessed based on the absolute value of the difference between the amount

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[46] Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking FERC Statutes and Regulations ¶ 32,563 (2002) (SMD).

[47] FirstEnergy also states that Midwest ISO did not explain whether charges on bids or offers that settle in the day-ahead market will be based on the number of bids, capacity of the bid, or some other measure to determine individual responsibility.

[48] MN DOC and INUCC suggest a charge of approximately 40 to 50 percent of the rate for Midwest ISO’s Schedule 17 for self-scheduling entities. They also state that self-scheduling entities should only be charged once rather than be charged for both generation injections and load extractions like other transactions.

market participants inject into the power system and the amount they withdraw from the power system; (3) market monitor, assessed on all load on a MWh basis; and (4) settlement costs, assessed on a customer charge basis.

**Reply Comments/Briefs**

38. WEP states that the Schedule 17 billing determinants for self-scheduled entities should only reflect their usage of the energy markets when such use is economic or to balance generation and load.

39. Missouri Commission states that while the activities of scheduling and bidding can be separated as recommended by other parties, it is preferable not to do so. Instead, the unbundling should encourage all market participants to bid all their resources into the market rather than self-schedule using their own resources to serve their own load. Missouri Commission argues that the best way for the spot market to function is to encourage all market participants to bid. Missouri Commission contends that scheduling and the pricing and trading of energy, as well as congestion management, are all joint products of the day-ahead process and therefore should not be separated, as recommended by other parties.[49] Missouri Commission also argues that all market participants should pay for scheduling and congestion management services and since the cost for these activities can not be separated from the cost of trading energy in the day-ahead market, these costs should not be unbundled. Instead, Missouri Commission proposes unbundling the Energy Market Service charge in Schedule 17 into day-ahead and real-time components because LSEs schedule generation and load through the day-ahead market process and balance the power system using the real-time market.

40. Ohio Commission maintains that bundled and unbundled customers will all benefit from the creation of the Energy Market Services. It points out that the creation of the markets will enhance wholesale competition in the entire Midwest ISO region, not just those areas that have elected to endorse retail competition; therefore, Ohio Commission argues that the proposed distinction of bundled versus unbundled retail customers is not appropriate for Energy Market Service. Ohio Commission argues that the Commission should consider the rate impacts on retail access states so that they are not unreasonably burdened to the point of hindering retail access meaning, retail access states should not bear the entire burden of the markets. Ohio Commission states that Midwest ISO's filing does not contain the information necessary to determine the burden on Ohio's ratepayers; therefore, Ohio Commission recommends postponing unbundling until Midwest ISO has operational experience with these services.

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[49] *See*, Exhibit No. MISO TO-1, p.12 and Jensen, Direct, p. 8.

41. Similar to its comments for Schedule 16, WPPI states that most commentors' recommendations are designed to shift as much of the costs as possible to a small group of "users" of the services so they can avoid paying the costs. If the bulk of the load in the footprint can avoid the cost of implementing and administering the energy markets, then the cost of the market will be so high that it will not be cost effective. WPPI asserts that if the Commission sees merit in the initial commentors' requests for exemption and unbundling, then the Commission should reconsider whether the LMP-based energy markets and the associated FTR hedging mechanism are worth pursuing, because the cost is high and there may be a more cost-effective path to achieve its pro-competitive and pro-consumer goals.

42. Midwest ISO responds that it is appropriate to allocate Schedule 17 costs between energy injections and withdrawals because the markets provide both an energy service and transmission service. Direct users will be those that transact energy business in the day-ahead and real-time energy markets. But these markets simultaneously reveal the LMPs which are the basis of the congestion management regime and are essential in providing real-time imbalance service. In short, all users of the transmission system derive a benefit from the existence of the energy market.

**Commission Determination**

43. The Commission finds that Midwest ISO's proposed unbundling of costs associated with Energy Market Service from the Schedule 10 ISO Cost Adder is reasonable, despite opposition seeking to shield bilateral and self-scheduled transactions from the charge. The presence of the markets produces global benefits to the Midwest ISO market participants, not the least of which are a more reliable and efficiently-used transmission grid, clear price signals for better infrastructure siting, better opportunities for demand response to participate in the markets, and price transparency, which clearly benefits even bilateral contract formation. The unbundled Schedule 17 charge assesses the costs to administer the energy market on all parties that inject and withdraw energy from the Transmission System as well as parties making bids and offers settled in the day-ahead market. The proposal is also consistent with the Commission's earlier guidance that the costs of establishing the Energy Markets Service should be spread broadly.[50] Moreover, the proposal for the Energy Market Service charge is similar to PJM's administrative charge which will facilitate the Commission's goal of establishing a common market between the Midwest ISO and PJM. The proposal also addresses the Commission's concerns regarding market implementation of rate design.[51]

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[50] Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,145 (2003).

[51] *See*, ISO New England, 89 FERC ¶ 61,339 at 62,019 (1999), *reh'g denied*,

44. The Commission disagrees with WEPCO and opposing state commissions who allege that self-scheduling entities, including bundled load, and bilateral contracts will not benefit as much from the energy markets established by Midwest ISO.[52] Self-scheduling entities and parties to bilateral transactions benefit through their use of the transmission grid which is made more reliable by the energy markets. For example, such transactions will likely be subject to fewer Transmission Loading Relief (TLR) calls with the establishment of energy markets.[53] The Commission believes preventing security violations before the fact through a security-constrained economic dispatch is a superior way of assuring reliability than relying on TLR procedures to relieve the constraint after the fact.

45. Additionally, self-scheduling entities and bilateral contract holders benefit from a more efficient transmission grid resulting from fewer TLRs under the proposed energy markets. As The Independent Market Monitor for the Midwest ISO (Midwest ISO IMM) stated,

> TLRs are inefficient because they make no attempt to optimize the curtailments (*i.e.*, to dispatch the generation with the largest effect on the flowgate). In addition, the TLR curtailments themselves are subject to limited resolution in both time (they are essentially hourly) and space (area versus node or bus).[54]

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91 FERC ¶ 61,016 (2000).

[52] The Commission believes that WEPCO, despite its assertions to the contrary, will likely receive net benefits as a result of the energy markets. The Midwest ISO's study indicates that Wisconsin entities will accrue total net benefits of approximately $51 million. The Commission expects the entire region to also benefit as a result of the energy markets. *See* Midwest ISO, The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets, Initial Results, March 2004.

[53] These energy markets are designed to transform the approach to addressing congestion on the transmission system from a process of subjecting physical transmission rights to TLRs to a financial process involving payment of appropriate congestion costs over the congested pathway. The Midwest ISO's regional dispatch will accommodate all transmission service requests, subject to transmission usage charges (external bilateral schedules may indicate their willingness to pay such charges). The energy markets will not eliminate TLRs completely (because there may, on occasion, be insufficient dispatch offers to resolve congestion at certain locations), but the Commission expects the number of TLRs to decrease significantly.

[54] Midwest ISO IMM, 2003 State of the Market Report, May 2004 at 49. *See* http://www.midwestiso.org/documents/imm/2003%20MISO%20SOM_Final%20Full%2

Operators of the grid are not able to curtail only that portion of the power flow from each transaction that affects the constrained flowgate. Thus, if only a small portion of the energy from a given transaction is passing through the constrained flowgate, the entire transaction may be curtailed, having a potentially large economic impact on the parties.

46. The Midwest ISO IMM concluded its study by stating,

> This analysis shows that the TLR process, on average, curtails more than three times the quantity of transactions as could be redispatched to achieve the same result. It also shows that for the individual flowgates, the TLR curtailments ranged from 73 percent more than the redispatch amount to 472 percent more (almost six times the redispatch amount). These results indicate that the TLR process is substantially inferior to a more discriminating approach to managing congestion, such as the Day 2 LMP markets. The Day 2 LMP markets will result in substantial efficiency benefits by redispatching the most economic and effective resources to manage network congestion.[55]

Accordingly, by reducing the number of TLRs, all market participants in the Midwest ISO region will benefit from a more reliable and efficient transmission grid including self-scheduling entities and parties conducting bilateral trades.

47. Moreover, the energy markets and FTR market will indicate the cost of congestion. Once the cost of congestion is determined, it can be compared with the cost of transmission upgrades, more efficient siting of generation, expanding demand response and providing redispatch at marginal cost so efficient means of reducing the congestion can be identified. Other factors aside, with the proposed energy markets generation has an incentive to locate at locations with higher LMPs rather than at locations with lower LMPs. Locations with higher LMPs are likely to have less supply relative to demand; therefore, generation additions will likely increase competition and lower prices including congestion costs. Additionally, the day-ahead market enhances demand response by giving loads more opportunities, if tight supplies and high prices were expected in real time, for deciding whether to consume energy or curtail consumption of energy (*i.e.*, essentially selling the energy in the real-time market). More demand response helps to mitigate shortages and mitigate peak period prices reducing the incentive and ability of generators to exercise market power benefiting parties to bilateral trades that choose to base the price of the energy in their bilateral transaction on the price of energy in the spot market.

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0Text%20Report.pdf.

[55] *Ibid.*, at 50-51.

48. The Court of Appeals has already addressed the issue of benefits and cost responsibility with respect to the Midwest ISO's Schedule 10 ISO Cost Adder.[56] The court found the Schedule 10 ISO Cost Adder covers the administrative costs of having an ISO and even if bundled and grandfathered loads are not in some sense using the ISO, they still get some benefit from having an ISO. The court likened the issue to the court system which is largely funded by taxpayers, at great expense, even though the vast majority of taxpayers will have no contact with that system (*i.e.*, will not use the system) in any given year. The public nevertheless benefits from having a system for the prompt adjudication of criminal offenses and the resolution of civil cases.

49. Likewise, bilateral transactions and self-scheduled transactions benefit by having energy markets. WEPCO acknowledges its likely use of the markets stating,

> This is not to say that an entity self-scheduling generation to meet its load will never use the Energy Market. It is likely that it will use the market in circumstances where it is economic to use the market instead of its own resources to balance generation and load.[57]

Therefore, WEPCO acknowledges the beneficial nature of the markets – the ability of all market participants to see the value of their own transactions and to instantly arrange an alternative sale or purchase when such a transaction is economical. However, neither WEPCO nor anyone else in the footprint would ever have the ability to use the Midwest ISO energy market when it is more beneficial to them than their own resources, if the Midwest ISO did not incur the costs to establish an energy market.[58] Therefore, even if WEPCO and other self-scheduling entities and parties to bilateral transactions are not directly buying or selling in the energy markets in a given hour, they must pay for having an energy market at their disposal, because they benefit from its existence.

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

[57] *See*, WEPCO initial brief at 5.

[58] The costs included in the Schedule 17 charge reflect infrastructure, software licensing, development and consulting, control area readiness, security constrained unit commitment, permanent back-up facility and financing costs.

50. Moreover, FirstEnergy is mistaken that Midwest ISO's proposal encourages purchases in the spot energy market over bilateral trades that would be more economically efficient.[59] The underlying premise of FirstEnergy's argument is that the self-schedule and bilateral transactions are not receiving any service or benefit from the day-ahead and real-time markets. As we have discussed above, Midwest ISO's Energy Market Service provides significant benefits to these transactions.

51. In the Commission's companion GFA Order, the Commission explains that there is no difference in the benefits GFAs receive from the energy market compared to those received by self-scheduled and bilateral transactions. Therefore, the Commission found that all GFAs should be assessed the charge in Schedule 17. The Commission finds that the proposed billing determinants, as modified by the concurrent GFA order, properly reflect the assessment of the charges to GFAs as determined in the concurrent order.

**Allocation of the Exit Fees Amounts**

**Background**

52. In the November 22 Order, the Commission accepted the Midwest ISO's proposal to assess an exit fee in the event that any transmission owner proposed withdrawing from the Midwest ISO prior to the end of the five year transition period.[60] The Commission approved the exit fee explaining that transmission owners form RTOs by transferring operational control of their facilities to the RTO and the RTO is dependent upon the ability to operate those transferred facilities for its existence. In other words, Midwest ISO depends on its transmission owners to ensure that the debt it incurs is paid. Each decrease in the potential use of these services caused by the withdrawal of a transmission owner diminishes the Midwest ISO's ability to recover its costs and to service its debt.[61]

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[59] FirstEnergy is also mistaken that the Midwest ISO proposal is not clear how it will assess charges under Schedule 17 on the capacity of the transaction. *See* Section II.A of Schedule 17 wherein Midwest ISO explains that charges are on a MWh basis.

[60] Midwest ISO proposed to defer collecting its start-up costs for Schedules 16 and 17 until operation of the markets commence. Midwest ISO explains that it would recover the start-up costs over a period of five years as part of the charges in Schedules 16 and 17.

[61] *See* Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 (2001).

The Commission set the exit fee allocation for a paper hearing because Midwest ISO had not adequately justified the proposed allocation and the Commission believed that changes to the billing determinants of the charges in Schedules 16 and 17 could potentially affect the exit fee allocation. On rehearing of the November 22 Order the Commission upheld its decision that exit fees imposed on withdrawing transmission owners to collect unrecovered start-up costs of FTR Service and Energy Market Service are reasonable.[62] Therefore, the only issue regarding exit fees set for the "paper hearing" is the amount of Midwest ISO cost allocation to withdrawing transmission owners and the impact of changes in the billing determinants of the Schedule 16 and 17 charges on that allocation.

**Midwest ISO Proposal**

53. Midwest ISO's exit fee would allocate to a withdrawing transmission owner a proportionate share of the unrecovered start-up costs incurred by the Midwest ISO to implement FTR Service and Energy Market Service. The withdrawing entity's assessment for unrecovered start-up costs is based on the load sinking within their transmission system relative to the entire Midwest ISO transmission system.

**Initial Comments/Briefs**

54. The Midwest ISO TOs argue that separate exit fees should not be included in individual Midwest ISO rate schedules and that exit fees should be as determined under the provisions of the Midwest ISO Agreement, where the matter is already addressed. Alternatively, they argue that exit fees in the individual schedules should reference but be subordinate to the withdrawal and exit fee provisions of the Midwest ISO TO Agreement and simply state the allocation principles that would be considered for Schedules 16 and 17.

55. Further, the Midwest ISO TOs assert that a withdrawing transmission owner should not bear costs greater than it would have been assigned if it had not withdrawn. Therefore, they argue that exit fees should be based on a representative period of service to the transmission owner under the relevant schedule and if such a determination can not be made, then the exit fee should be determined through negotiation on a case-by-case basis.[63]

[62] *See* Midwest Independent Transmission System Operator, Inc., 103 FERC ¶ 61,035 (2003).

[63] Midwest ISO TOs do not define a representative period of service.

56. MN DOC and IN UCC support the concept of exit fees in order to prevent parties from avoiding legitimate costs incurred on their behalf, such as market start-up costs. They state that they will defer to other parties as to the appropriate level of exit fees.

57. WPPI supports Midwest ISO's proposed exit fees. WPPI disagrees with the contention that the exit fees contradict the Midwest ISO Agreement. WPPI argues that the withdrawal provisions merely make explicit and quantify the financial obligations at the time of withdrawal.

**Commission Determination**

58. The issue here is not whether Midwest ISO can impose the exit fees in Schedules 16 and 17 on withdrawing transmission owners to collect unrecovered start-up costs related to FTR Service and Energy Market Service, as the Commission has already found that as a matter of policy it is reasonable for Midwest ISO to do so. The only issue set for the paper hearing regarding exit fees was the allocation of unrecovered costs to be assessed to a withdrawing entity.

59. Midwest ISO is proposing to assess a proportionate share of the unrecovered costs to a withdrawing transmission owner based on the withdrawing entity's load sinking in its transmission system relative to the entire Midwest ISO transmission system. In the November 22 Order, the Commission stated, in part, that Midwest ISO had not adequately justified the proposed allocation and instructed the parties, including Midwest ISO, to address the issue in the "paper" hearing.[64] However, the Midwest ISO did not address the reasonableness of the allocation of exit fees in its brief. Accordingly, the Commission rejects the Midwest ISO's proposed allocation of exit fees for Schedules 16 and 17 as unsupported. The Midwest ISO has been able to negotiate withdrawal fees in the past to which parties throughout the region were agreeable and the Commission found reasonable;[65] therefore, the Commission finds that, in light of the rejection here of the proposed allocation, Midwest ISO should negotiate with a withdrawing transmission

[64] The Commission was also concerned that a change in the billing determinants of Schedules 16 and 17 may necessitate a change in the allocation of the exit fee. Since the Commission is not requiring any changes in the billing determinants of Schedules 16 and 17 at this time, the Commission does not view the billing determinants of Schedules 16 and 17 as requiring a change in the exit fee allocation.

[65] In Docket No. ER01-123-000, as part of a comprehensive settlement, Midwest ISO successfully negotiated withdrawal fees with Commonwealth Edison Company, Illinois Power Company and Ameren Corporation to facilitate their withdrawal from the Midwest ISO. *See*, Illinois Power Company, 95 FERC ¶ 61,183 (2001).

owner on a case-by-case basis. Midwest ISO is required to file a compliance filing within 45 days from the date of this order to replace the proposed allocation with a statement in Schedules 16 and 17 that exit fees imposed on withdrawing transmission owners will be negotiated and filed with the Commission. This action does not prejudice Midwest ISO from refiling a proposal with adequate support for the assessment of unrecovered costs to a withdrawing entity.

**Compliance Filing in Docket No. ER02-2595-003**

60. In the November 22 Order the Commission stated that it had concerns regarding the specificity of Midwest ISO's formula rate because the rate sheets did not specify the actual calculations of the costs of the services in Schedules 16 and 17. The Commission noted that this lack of specificity was contrary to its policy with respect to formula rates.[66] Accordingly, the Commission required Midwest ISO to file a compliance filing that specifies the formula calculations in the rate sheets.

61. Generally, each revised formula in Schedules 16 and 17 adds the estimated costs of providing the service for the following month to a true-up mechanism for the prior month and divides the total by the proposed billing determinant.[67] The cost of providing service, exclusive of the true-up mechanism, is calculated in five components.

62. The first component (A1) recovers the cost of the Market Operations Department (MOD) less adjustments for depreciation expense, interest, finance costs and amortization costs. Midwest ISO proposes to allocate the costs of the MOD between Schedules 16 and 17 on a labor basis since over 80 percent of the costs are labor-related. The second formula component (A2) recovers the labor-related costs of divisions other than MOD to the extent they provide support (*e.g.*, engineering) for services associated with each schedule.[68] The third formula component (A3) allocates the costs of certain departments,

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[66] *See*, Maine Yankee Atomic Power Company, 42 FERC ¶ 61,307, *order denying reh'g*, 43 FERC ¶ 61,453 (1988).

[67] For FTR Service under Schedule 16, the proposed billing determinants are the estimated total FTR volume of all FTR Holders expressed in MW for each hour of the month. The proposed billing determinants in Schedule 17 for Energy Market Service are the estimated sum of all injections and extractions in MWh from the transmission system and all bids or offers in MWh that settle in the day-ahead market, but not actually injected MWh into or extracted MWh from the transmission system in the real-time market (*i.e.*, virtual trades).

[68] The labor-related costs include costs in those divisions booked to Accounts 408.2 (FICA taxes), 920 (salaries and wages), 921 (supplies and other) and 926 (benefits) of the Uniform System of Accounts.

less adjustments for depreciation, interest, finance costs and amortization costs, that provide administrative and general (A&G) services (*e.g.*, executive management and human resources) on a labor-basis to calculate the portion of those departments that are applicable to the services under Schedules 16 and 17. The fourth component (A4) calculates depreciation on non-General Plant assets based on a study of the use of the assets. The fifth component (A5) calculates the interest, finance costs and amortization costs by assigning the costs to each schedule based on the use of the proceeds of the financing activity.

**Protests**

63. According to the Midwest ISO TOs, the proposed formula rates lack the specificity required by Commission policies. They argue that a formula rate should be clear enough both in its calculation and source of data to allow one to compute the rate given the necessary inputs and that Midwest ISO's formula rates lack this clarity. The Midwest ISO TOs identify the depreciation and amortization lives and calculation of wages and salaries in Part A.1 of the formula as two specific parts of the formula that are inadequate. The Midwest ISO TOs state that formula components A4 and A5 do not state the applicable depreciation rates and amortization schedules to be applied to non-General Plant Assets. They assert that Midwest ISO should be required to state in the formulas the depreciation rates to be used and provide justification for those depreciation rates, otherwise the Midwest ISO TOs believe that the Midwest ISO could change its depreciation rates in violation of the Federal Power Act (FPA).[69]

64. The Midwest ISO TOs also state that the proposed formula rates lack specificity with respect to direct assignment costs. They argue that a better method would be to track direct assignment costs through specific accounts. The Midwest ISO TOs also assert that the proposed formulas lack specificity regarding the cost allocations among Schedules 10, 16 and 17.[70] Further, they argue that the formula definitions are unclear and that the true-up mechanism is vague.[71]

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[69] Midwest ISO TOs *cite* 16 U.S.C. § 824(d) and 18 CFR Part 101 Depreciation Accounting, Order No. 618, 1996-2000 FERC Stats & Regs., Regs. Preambles ¶ 31,104 at 31,695 n. 25 (2000).

[70] The Midwest ISO TOs express concern that there are some categories of costs that Midwest ISO currently is recovering under Schedule 10, which has a cap, which Midwest ISO may seek to recover under Schedules 16 and 17, which do not have a cap.

[71] The Midwest ISO TOs raise an additional issue (*i.e.*, language in Schedule 10 is insufficient to preclude Midwest ISO from recovering imprudent Schedule 16 and 17 expenses).

65. The Midwest ISO TOs also assert that Schedules 16 and 17 should explain or at least reference the relationship of the exit fees in the schedules to the withdrawal provisions of the Midwest ISO Agreement. The Midwest ISO TOs propose that if the exit fee formulas are included in Schedules 16 and 17, then the schedules should clarify that such formulas are simply the allocation principles applicable to the schedules as part of determining the exit fee under the Midwest ISO Agreement.

66. Trial Staff states that Midwest ISO should post the data inputs of the formula on its website so that market participants have access to the data and can determine and verify the charges in Schedules 16 and 17.[72] According to Trial Staff, this rate information may help to determine if Midwest ISO's allocation methods are producing reasonable allocations on an ongoing basis and could be used to investigate whether a given cost belongs in Schedule 10 rather than Schedules 16 or 17. Further, Trial Staff asserts that archiving these monthly rate calculations on its website will allow customers to monitor cost trends and allocations. Even with the data inputs made public, Trial Staff expresses concern that the rates may not be just and reasonable and suggests that the Commission require Midwest ISO to periodically file the billing data (*e.g.*, every two years), pursuant to section 205 of the FPA, in order to support its costs and allocation methods. Otherwise, Trial Staff points out, customers may have to file complaints under section 206 of the FPA and bear the burden of proof to show such rates are unjust and unreasonable.

**Midwest ISO's Response**

67. Midwest ISO's clarifies that the depreciation lives it uses in setting the depreciation rates is in accordance with General Acceptance Accounting Principles.[73]

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[72] Trial Staff asserts that this data should include allocation percentages as well as a breakdown of the rate divisors used by Midwest ISO.

[73] Midwest ISO states that it uses the following depreciation lives:

| Asset | Life |
|---|---|
| Hardware | 3 years |
| Software | 5 years |
| Furniture and Fixtures | 7 years |
| Telecommunications | 7 years |
| Leasehold Improvements | 20 years |
| ICCS Software | 7 years |

With respect to its amortization schedules, Midwest ISO states that it expects to have only two amortization items included in the rates.[74] Midwest ISO also explains generally its process for determining wages and salaries and states that detail regarding its true-up mechanism is already provided in the schedules. Additionally, Midwest ISO states that any reference to the Midwest ISO Agreement's withdrawal provisions in the exit fee sections of Schedules 16 and 17 is unnecessary because the Midwest ISO TOs rights have not been changed by the creation of Schedules 16 and 17.[75]

**Commission Determination**

68. The Commission finds that the formulas in Midwest ISO's compliance filing are still not specific enough to operate as formulas because Midwest ISO would continue to have discretion with respect to calculating the charges. Accordingly, the Commission finds that Midwest ISO has not complied with the November 22 Order. The Commission directs the Midwest ISO to file a compliance filing to revise the formula rates in Schedules 16 and 17 to add the specificity described below.

69. Midwest ISO uses in its formulas many capitalized terms that are not defined in the schedules. Midwest ISO must define each of these terms. Additionally, Midwest ISO is required to state the accounts in the Uniform System of Accounts used in each of the formula components. The Midwest ISO states in section B of the schedules that the deferred pre-operating costs of each schedule are recovered under the respective schedule over a five year period beginning on the date of service. However, the tariff sheets with the formula rates do not explicitly explain the treatment of deferred pre-operating costs. Therefore, to the extent deferred pre-operating costs are recovered in formula rates, Midwest ISO must clarify in its formulas the treatment of the deferred pre-operating costs to avoid the possibility of the Midwest ISO over recovering its costs. If Midwest ISO intends to recover its deferred pre-operating costs apart from the formula rates, it must clarify Schedules 16 and 17 to explicitly explain the treatment of deferred pre-operating costs.

70. More specifically, for component A1 of the formula rates, Midwest ISO must define the capitalized term, "Market Operations Department." Since the total operating costs of the MOD are split between Schedules 16 and 17, the revised definition must reflect that only costs supporting Schedules 16 and 17 activities are performed in the MOD (*i.e.*, this element must not include any costs associated with Schedule 10 activities). The definition must also reflect the accounts in the Uniform System of

[74] The first item is the amortization of start-up costs which the schedules state will be over five years and the second item is the amortization of capitalized note offering costs.

[75] Midwest ISO *cites* November 22 Order at P 53.

Accounts to which MOD costs are booked. Finally, Midwest ISO has stated in its transmittal letter that over 80 percent of the costs in the MOD are labor-related. Midwest ISO should evaluate the nature of the costs that are not labor-related and develop allocators for such costs. If these costs in the MOD are not related to any generic allocation, Midwest ISO is directed to fix the allocator of costs not related to labor (*e.g.*, 40 percent costs are related to Schedule 16 and 60 percent are related to Schedule 17) in the formula.[76]

71. For component A2 of the formula rates, Midwest ISO allocates a portion of the labor-related costs in all the divisions that support the services in Schedules 16 and 17 except the MOD. Midwest ISO is directed to clarify in formula component A2 that, in addition to excluding the costs associated with the MOD, the Midwest ISO also excludes divisions or departments performing Administrative and General (A&G) activities from the calculations in component A2 since Midwest ISO proposes recovering its A&G costs in formula component A3.

72. The Commission agrees with the Midwest ISO TOs that the capitalized term "Total Administrative Costs" must be clearly defined in formula component A3. The definition, as proposed, does not limit the costs that can be included; thereby, giving Midwest ISO discretion in the operation of the formula rates.[77] In the definition, Midwest ISO is hereby directed to reference the accounts of the Uniform System of Accounts to which Midwest ISO will be booking the A&G costs included in "Total Administrative Costs" and revise the definition to preclude double recovery of costs booked to these accounts by clarifying the definition of "Total Administrative Costs" to exclude the costs associated with the MOD and any division included in component A2.[78]

73. In component A4, the Midwest ISO has too much discretion in the calculation of depreciation of non-general plant assets in the formula rates. Including the depreciation lives in Midwest ISO's answer to protests is not sufficient to remedy the discretion because the Midwest ISO could still change the depreciation rates (and as a result change

[76] Subsequent, changes to these allocations would constitute a change in rate necessitating a filing under section 205 of the FPA.

[77] Similarly, the definition of Administrative Salaries and Wages should be redefined since it also lacks specificity.

[78] Moreover, the Commission notes that the definition of "Division Salaries and Wages" is different in Schedules 16 and 17. The definition in Schedule 16 references MOD while the corresponding definition in Schedule 17 references non-MOD divisions. Midwest ISO should correct both definitions to exclude MOD and divisions performing A&G functions.

the charges) at its own discretion. Thus, the Commission will require the Midwest ISO to establish depreciation rates for its non-general plant and include the depreciation rates in the formula. Upon acceptance, the depreciation rates will be considered prescribed rates under section 302 of the FPA. We remind Midwest ISO that to change these approved depreciation rates, the Midwest ISO would have to file the revised rates and obtain Commission approval prior to implementing the change.

74. In addition, we find that Midwest ISO must not have the discretion to modify the depreciation expense allocation for non-general plant assets amongst Schedules 10, 16 and 17. Therefore, we will require the Midwest ISO to complete studies on the use of the assets and modify component A4 of the formula to incorporate fixed allocation percentages of depreciation on non-general plant assets based on the results of the studies. For example, if after examination of the studies on the use of the assets, Midwest ISO determines that 40 percent of the depreciation on non-general plant assets pertains to Schedule 10, 20 percent pertains to Schedule 16 and 40 percent pertains to Schedule 17. The Midwest ISO must modify the component A4 in both formulas to state the fixed percentage of depreciation expense on non-general plant assets that will be included in the charge.[79] These fixed allocation percentages will preclude Midwest ISO from changing at its discretion the amount of depreciation expense to include in each charge.[80] Additionally, because the Uniform System of Accounts does not distinguish between the functions present here (*i.e.*, transmission, FTRs, and energy markets), the Commission directs the Midwest ISO to use specific sub-accounts, functionalized by schedule, to record the depreciation expense of assets that pertain to Schedules 10, 16 and 17.[81] This requirement of sub-accounts, functionalized by sub-account, will permit stakeholders to determine if the formulas' fixed allocation percentages for depreciation expense associated with Schedules 10, 16 and 17 are representative of the amount actually included in the corresponding sub-account.[82]

75. Since the capitalized terms in component A5 are not defined, Midwest ISO must define these terms. The Commission also needs to know where the costs are being booked. Therefore, in the definitions specify the accounts in the Uniform System of

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[79] Component A4 of the formulas should identify the plant account and function to which the depreciation expense was booked.

[80] If these percentages need to change to reflect new circumstances, Midwest ISO must make a section 205 filing with the Commission to change the fixed percentages.

[81] Midwest ISO is also directed to include these sub-accounts in the notes of its FERC Form No. 1.

[82] We note that the Commission is concurrently issuing a Notice of Inquiry that seeks comment on whether the current Uniform System of Accounts is adequate with respect to RTO and ISO cost accounting and financial reporting.

Accounts and reflect the amortization period relating to capitalized note offering costs. Midwest ISO proposes to directly assign these costs based on the use of the proceeds of the financing. This assignment of costs gives the Midwest ISO too much discretion in the allocation of these costs amongst Schedules 10, 16 and 17. Therefore, we will impose restrictions on component A5 similar to those imposed for component A4. Specifically, Midwest ISO must determine fixed allocation percentages for Schedules 10, 16 and 17 and include them in the formulas.[83] Moreover, because the Uniform System of Accounts does not distinguish between the functions present here (*i.e.*, transmission, FTRs, and energy markets), the Commission directs the Midwest ISO to use sub-accounts, by schedule (*i.e.*, Schedules 10, 16 and 17) so that market participants can check the formulas' fixed percentage allocations included in the rates with the percentage allocations included in Midwest ISO's books. Further, Midwest ISO is directed to clarify that it will not seek to recover the loan principle associated with any asset for which it is already recovering depreciation in component A4.

76. We agree with Trial Staff that stakeholders would benefit from Midwest ISO providing the data inputs, both the initial monthly estimates and the actual true-up costs, with cost allocations and supporting documentation on its website so that market participants can independently perform the formula calculations. Moreover, archiving this information on the web site will permit the stakeholders to monitor cost trends and allocations by Midwest ISO.

77. The Commission denies the Midwest ISO TOs' request that the formulas calculating the exit fees contained in Schedules 16 and 17 refer to the withdrawal provisions of the Midwest ISO Agreement. The November 22 Order explained that it is reasonable for Midwest ISO to assess the TOs an exit fee for early withdrawal and that the rights of the TOs under the Midwest ISO Agreement have not been changed by the exit fee requirements of Schedules 16 and 17 in the Midwest ISO OATT.[84] Since the relationship between the withdrawal provisions of the Midwest ISO Agreement and the exit fees in Schedules 16 and 17, has already been established the requested clarification of referencing such relationship is unnecessary.

<u>The Commission orders:</u>

(A) The late motions to intervene submitted by the parties described herein are hereby granted.

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[83] Modifications to these fixed allocation percentages will also require a filing under section 205 of the FPA.

[84] *See* November 22 Order, 101 FERC ¶ 61,221 at P 54.

(B) Midwest ISO's compliance filing is hereby accepted in part and rejected in part.

(C) Midwest ISO is hereby directed to submit a compliance filing, consistent with the discussion herein, within 45 days of the date of issuance of this order.

By the Commission.

( S E A L )

Linda Mitry,
Acting Secretary.