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Midwest ISO Energy Markets by Design

The experience of the Midwest ISO demonstrates that creative solutions can be developed to meet the unique needs of a region by implementing Energy Markets that reflect the requirements of the region while also adhering to sound economic principles.

Richard A. Drom, Michael L. Kessler and Ronald R. McNamara

I. Introduction

When the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) Energy Markets successfully commenced on Apr. 1, 2005, the Midwest ISO established precedent as being the first multi-state RTO without a historical tight power pool to implement a wholesale energy market with centralized economic dispatch and full locational marginal pricing for congestion. This achievement is remarkable given the many challenges overcome by the Midwest ISO, including: (1) accommodating existing transmission agreements that constituted a significant percentage of market transactions in the new energy market structure without abrogating the contractual rights of the transmission customers operating under those agreements; (2) successfully coordinating all of the market initiatives with the diverse representatives of the 15-state Organization of MISO States (OMS); (3) developing and implementing an equitable methodology for allocating financial transmission rights (FTRs) despite a lack of precedent in this area; (4) developing a single region-wide transmission rate design that

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took into account the vast geographical differences in marginal losses across the Midwest ISO region; (5) integrating 23 distinct control areas into a single region-wide market design.

The Midwest ISO Management recognized that the establishment of viable Energy Markets required that many critical market design issues be addressed and resolved upfront in order to ensure system and market reliability, and the effectiveness of the security-constrained economic dispatch platform that lies at the heart of the Energy Markets. A key example of such a critical market design issue is the resolution of existing grandfathered agreements (GFAs). Moreover, the Midwest ISO deemed it essential to design and implement the Energy Markets in consultation with the Midwest ISO region's state regulatory authorities as a group, in order to arrive at collectively discussed and holistic solutions rather than a more piecemeal approach. The Midwest ISO also considered it crucial to pursue all critical market design issues, such as the equitable allocation of FTRs, with the involvement of all market stakeholders through meetings, conference calls, committee and task force activities, and e-mail correspondence.

The innovative Energy Markets Tariff (EMT) that embodies the initial resolution of the above issues, and undergirds the successful start of the Energy Markets, consists of over 2,000 pages and is available on the Midwest ISO Web site for review.[1] Given the complexity of the EMT, this article will merely highlight how Midwest ISO management was able to work cooperatively with its stakeholders, federal and state regulators, and other industry participants to develop compromise solutions on some of the key issues to enable the Energy Markets to commence.

Among the critical market-design issues: the resolution of existing grandfathered agreements.

II. Background

The EMT is the result of more than three years[2] of persistent work by the Midwest ISO management and its many stakeholders (including integrated investor-owned utilities, municipally owned utilities, independent transmission operators, independent generators, energy marketers, end users, and state utility commissions) to painstakingly develop a workable market design that could accommodate stakeholder needs while preserving the essential components of a reliable and competitive electricity market based on centralized dispatch. After almost a year of discussion, the Midwest ISO filed an initial version of the EMT on July 31, 2003, with the Federal Energy Regulatory Commission (FERC). Stakeholders raised many concerns regarding this initial filing (including jurisdictional, procedural, and substantive market design concerns), and the Midwest ISO withdrew it in early October 2003. The Midwest ISO, however, requested FERC to provide additional guidance regarding the essential elements of an EMT. FERC provided such guidance in an Oct. 29, 2003, order that greatly facilitated additional valuable stakeholder discussions.[3] The Midwest ISO labored extensively with its stakeholders to develop the Mar. 31, 2004, version of the EMT that was ultimately approved by FERC.

In response to concerns identified by stakeholders regarding the EMT, the Midwest ISO conducted extensive discussions in almost a dozen different stakeholder committees, and undertook a comprehensive educational "road show" to identify and address as many of the stakeholder needs as possible. FERC conditionally approved the EMT on Aug. 6, 2004.[4] Since then, the Midwest ISO has made numerous filings with FERC to fine-tune the EMT.[5] With FERC's blessing and the participation of all stakeholders, the Midwest ISO began implementing the market design embodied in the EMT on Apr. 1, 2005.[6]

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III. Some Key EMT Issues

A. GFAs

In part because the Midwest ISO's market participants had no history of tight power pool operations, approximately 23 percent of the load in the Midwest ISO Region was being served through pre-existing or "grandfathered" long-term transmission service agreements that contained specific scheduling, transmission loss, and other terms and conditions that were potentially inconsistent with the market design embodied in the EMT.[7] To address how these pre-existing agreements would be accommodated in the Midwest ISO's new Energy Markets, FERC issued a May 26, 2004, order setting these GFAs for hearing.[8] The hearing addressed the issue of whether certain of the GFAs should be "carved out" of the Energy Markets, and the related reliability and economic consequences of doing so. This involved the determination, among other things, of which GFAs contained provisions prohibiting them from being modified by the EMT under the general "just and reasonable" standard of the Federal Power Act for FERC-directed contract modification, and instead required any such change to meet the higher *Mobile-Sierra* "public interest" standard.[9]

After extensive hearings and discovery, FERC ultimately held on Sept. 16, 2004, that GFAs representing approximately 9 percent of the load in the Region did not contain *Mobile-Sierra* restrictions, and therefore could maintain their GFA status but would otherwise be required to select between three different options for treatment under the EMT.[10] Alternatively, these GFAs were given the option to fully convert to service under the EMT.[11] On the other hand, the Commission determined that GFAs representing approximately 10 percent of the load in the Region either contained explicit *Mobile-Sierra* provisions or were silent on the applicable standard of review, and thus would essentially be "carved out" from the EMT.[12] The Midwest ISO worked patiently with the carved out GFA parties to design compromise congestion management and loss recovery provisions to meet their unique needs. On Jan. 19, 2005, the Midwest ISO proposed EMT revisions reflecting the rules for administering carved-out GFAs.[13]

In part because market participants had no history of tight power pool operations, 23 percent of the load in the Midwest ISO Region was being served through pre-existing agreements.

Finally, finding it unclear whether certain GFAs should not be subject to the EMT, the Commission directed that the Midwest ISO and the parties to these agreements engage in settlement discussions, or else participate in hearings, to determine how the parties to such contracts should interact with the Midwest ISO.[14] After extensive settlement negotiations, the Midwest ISO reached settlement agreements with those parties on Apr. 1, 2005, the very day the Energy Markets commenced.[15]

Among the issues addressed in the settlements was the treatment of particular load, generation, and transmission rights depending on whether they are located within the Midwest ISO Region and/or use the Midwest ISO's transmission facilities. Certain of these GFAs involved "integrated transmission agreements," pursuant to which load is served both inside and outside the Midwest ISO footprint through transmission and/or generation facilities owned by both Midwest ISO members and non-Midwest ISO members.

As a result of these unique GFA characteristics, consideration was given to the manner in which these GFAs should be treated as "out of market," and how such treatment would differ from GFAs that were "carved out" of the energy markets. For example, issues addressed included determining which party should be responsible for providing the Midwest ISO with scheduling and other data necessary to enable the Midwest ISO to implement each settlement, and the extent to which each GFA party would be

subject to certain Midwest ISO charges.

B. Coordinating solutions with the OMS

Throughout the development of the EMT, the Midwest ISO Management worked with representatives from each of the states in the Region to help educate them about the EMT and to gain a better understanding of the unique needs of each of the states. The formation of the OMS in May 2003 greatly assisted this process by establishing a more formal framework and process for continuing discussions with the state representatives as a group. Some of the OMS states had elected to implement electricity retail choice for their citizens; others had maintained a more traditional retail paradigm in which utilities had defined service territories in which they were the sole provider of retail services. As a result, negotiations on energy markets with states on an individual basis had been less successful.

A key energy market design issue that had to be resolved involved the ability of the state commissions to obtain confidential data and information from the Midwest ISO and its Independent Market Monitor (IMM) on a basis comparable to FERC's access to such information. FERC's Aug. 6, 2004, Order directed the Midwest ISO to adopt the approach used by PJM Interconnection, LLC regarding the access of state commissions to confidential data.[16] The OMS requested rehearing of this directive of the Aug. 6 Order, objecting to a wholesale adoption of the PJM model, and seeking an opportunity to submit an Offer of Proof in support of its position, and to discuss and develop an alternative proposal with stakeholders.[17] The Commission allowed the OMS to submit an Offer of Proof,[18] which was filed on Feb. 11, 2005. However, in the discussions among the Midwest ISO, the OMS and stakeholders, a number of stakeholders opposed the framework proposed by the OMS.

OMS and the stakeholders disagreed on the permissible nature, scope, and purposes of information requests and objections thereto.

The matters on which the OMS and the stakeholders disagreed included the permissible nature, scope, and purposes of information requests and objections thereto; the accessibility of confidential "streaming" data; whether affected parties should be given notice of, and an opportunity to challenge, any state requests for information; whether, and to what extent, state agencies should be allowed to share and discuss confidential information among themselves; the possible limitations on a state agency's obligation to defend against third-party requests for confidential information the agency had obtained from the Midwest ISO or its IMM; and the available relief, remedies, and forum for addressing breaches of confidentiality obligations. The Midwest ISO sought to bridge the parties' disparate positions by submitting an alternative proposal to FERC, which allowed the PJM model to be modified and adapted to the Midwest ISO's context in ways that balanced the interests of the OMS, the stakeholders, the Midwest ISO, and the other market participants.[19]

C. Allocating FTRs

FERC regulations require that an RTO develop congestion management tools based upon market mechanisms.[20] Based upon the success of FTRs in other RTOs, the Midwest ISO Management worked extensively with its stakeholders to develop equitable tools for allocating FTRs to load to protect baseline generation transmission service. After many months of negotiations, the Midwest ISO Markets Subcommittee endorsed a methodology for FTR allocation that was approved by FERC. This methodology underwent further revisions in response to stakeholder input and FERC compliance obligations that further refined the FTR allocation process to address the needs of GFAs.[21]

The Midwest ISO's stakeholders, just like its membership,

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are a very diverse group with a number of differing interests. In developing an appropriate FTR allocation methodology for the Midwest ISO, the concerns of all stakeholders had to be taken into account. The stakeholder process to develop FTR allocation procedures began in mid-2001 and continued up through the initial allocation of FTRs that concluded in January of this year.

One of the key issues that the Midwest ISO and stakeholders had to resolve leading up to the initial FTR allocation was the issue of whether FTRs should be allocated automatically to market participants based on historical uses of the transmission system or through a flexible nomination system that allowed entities to request FTRs based on their anticipated needs. The FTR allocation process eventually arrived at by the Midwest ISO and stakeholders struck a middle ground between these two approaches.

Despite an apparently "constantly moving target" of stakeholder concerns, the Midwest ISO Management was able to successfully implement a complex FTR allocation methodology. This "compromise" methodology used a network model, based on fair parameters and developed with extensive stakeholder input, to allocate FTRs in a manner that appropriately represented existing transmission entitlements while protecting the financial feasibility of allocated FTRs. The development and application of a Simultaneous Feasibility Test (SFT) helped to ensure that allocated FTRs would be economically feasible and reduce the need to uplift the costs of FTRs to transmission customers.[22] The process used to develop the FTR allocation methodology was approved by FERC and was implemented by the Midwest ISO in a manner that provided sufficient flexibility so that the entire allocation process could be "fine-tuned" in the months leading up to the initial FTR allocation. The Midwest ISO assisted parties in understanding the consequences of FTR requests, and conducted the first successful allocation of FTRs during the several months leading up to market start using a unique "four-tier" allocation methodology that was designed as part of a joint effort of Midwest ISO Management and its stakeholders.[23]

The FTR allocation process eventually arrived at struck a middle ground between two approaches.

The FTR allocation process used by the Midwest ISO allows market participants to nominate transmission entitlements for FTR allocations in a series of four tiers.[24] In each of the four tiers, market participants may nominate up to a set percentage of their eligible transmission entitlements for FTR allocations. The Midwest ISO then performs a SFT and allocates FTRs for all nominations that are feasible. FTR nominations during each of these four tiers are voluntary; however, to the extent that a voluntary decision not to nominate FTRs from base load generation resources within the first two nomination tiers results in there not being counterflow available to support the simultaneous feasibility of other market participants' FTR nominations, the Midwest ISO's allocation methodology gives entities that were not granted FTRs during these tiers additional opportunities to get their requested FTRs.

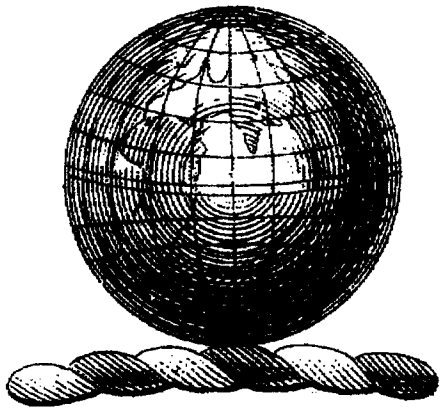
After the conclusion of the second tier of the allocation process, entities are required to accept FTRs that were needed to provide the necessary counterflows to make feasible the FTRs that were nominated by others, but not granted in the first two tiers. This process, known as the "restoration allocation," assigns counterflow FTRs to market participants, as necessary, to make feasible nominated, but previously infeasible, FTR requests.[25] This "restoration allocation" was a key component of the compromise FTR allocation methodology because it strikes a balance between the views of certain stakeholders that wanted to have mandatory FTR allocations based on historical uses of the transmission system in order to protect their existing transmission entitlements, and other stakeholders

that wanted the flexibility to nominate and be allocated FTRs based on their anticipated needs. The Midwest ISO also developed procedures to enable parties to exchange FTRs through monthly auctions,[26] as well as obtain residual FTRs that may exist under the SFT.[27]

This compromise allocation methodology developed by the Midwest ISO and its stakeholders was accepted by the Commission and implemented in the months leading up to the start of the Midwest ISO markets. The results of the Midwest ISO's initial FTR allocation show that FTRs were allocated to market participants for approximately 95 percent of all nominated values, indicating that the compromise allocation methodology was very successful in allocating to market participants the FTRs that they thought they needed.[28]

D. Sharing responsibilities between the Midwest ISO and control area operators

A key concern of many stakeholders was to ensure a clear demarcation of responsibilities between the operators of control areas within the Midwest ISO Region and those tasks that the RTO would perform. FERC ordered that the responsible parties negotiate and attempt to reach a voluntary settlement of these contentious issues.[29] After weeks of settlement discussions, the parties were able to propose, with virtual unanimity, a detailed Balancing Authority (BA) Agreement that they filed with FERC on Oct. 5, 2004. FERC approved the BA Agreement with minor compliance requirements on Feb. 18, 2005.[30] The Midwest ISO met such compliance requirements on Mar. 21, 2005, with respect to the incorporation of settlement provisions in the EMT; and on Mar. 28, 2005, with regard to the amendment of



the BA Agreement to deal with GFAs.

The BA Agreement addressed all key aspects of operations and reliability for both planning and real-time operations. In a nutshell, the Agreement provided for the RTO to be responsible for operations up until the immediate real-time (i.e., up until five minutes from the time of transmission service). The BA will have responsibility for specific defined activities during the final five minutes. The allocation of functions and responsibilities was largely based on the "Functional Model" of the North American Electric Reliability Council (NERC) on this subject,[31] and on a "Reliability Charter" reflecting results of the Midwest ISO's prior discussions of these issues.[32]

In addition, the BA Agreement included liability and indemnification provisions that shielded the parties from liability for ordinary negligence, and limited to direct damages their exposure for gross negligence or intentional misconduct.[33] The BAs were also protected from liability for good faith attempts to comply with the directives of the Midwest ISO.[34] The BA settlement enabled the BAs to recover costs they incur in implementing the BA Agreement.[35] The BA Agreement further stipulated the confidential treatment of relevant information,[36] and the applicability to the Agreement of the *Mobile-Sierra* standard of judicial review.[37]

E. Transmission losses

Unlike a relatively compact region, the Midwest ISO Region extends thousands of miles and covers all or part of 15 states. This enormous size results in significant differences in physical transmission losses that are experienced in transmission transactions depending on where within the Midwest ISO Region a transaction takes place. These differences are estimated to vary between virtually no losses in some regions to transmission losses of more than 15 percent in other regions.

As the FERC-approved RTO for the Region, it was the Midwest ISO's responsibility to develop a marginal loss methodology that would appropriately account for

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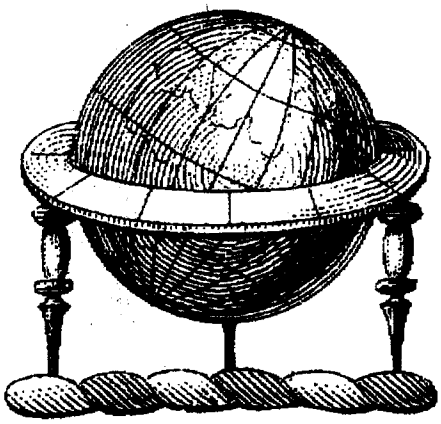
marginal losses and also respect the regional differences in transactions within its footprint. Midwest ISO management worked with its stakeholders to develop and implement efficient marginal loss protocols that would accomplish this goal. Generally, marginal losses tend to be approximately double the average losses that occur in a transmission system, and the methodology developed by the Midwest ISO had to develop loss crediting provisions that appropriately reflected this fact while at the same time meeting the complex needs of its stakeholders operating in different geographical areas.

In order to reflect accurate information regarding the effect of transmitting power across a large geographic region, the Midwest ISO and its stakeholders decided to adopt a methodology that not only incorporates transmission losses into locational marginal prices but does so based on the marginal, rather than average, impact. The use of marginal losses, as compared to average, improves both transparency and reliability because nodal prices are a more accurate signal to participants. In this way, transmission loss charges will be based on the incremental losses experienced with a given transaction, and not on a regional estimation that does not accurately reflect the effect of that transaction on the integrated network.[38] The use of a marginal loss methodology at each node was adopted by the Midwest ISO and its stakeholders because it aligns the costs of the transmission losses associated with the transactions responsible for those costs and thereby more accurately reflects the true costs of using the transmission grid. This increased accuracy improves the dispatch process and sends more efficient price signals to the market participants seeking to



optimize their transactions on the grid.

The use of a marginal loss methodology to calculate and assess the costs of transmission losses in the Midwest ISO footprint, while efficient, necessarily leads to an overcollection of transmission loss revenues from the users of the system because their actual physical losses will not equal the total marginal losses. This surplus collection of the costs associated with transmission losses must be returned to the market participants using the transmission grid. To solve this reimbursement problem, the Midwest ISO and its stakeholders developed a crediting mechanism that allows the Midwest ISO to reimburse surplus transmission losses in an equitable manner, without eroding the price signal benefits provided by including a marginal losses component in LMPs. Surplus transmission losses are refunded to market participants on a sub-regional basis. The reimbursement methodology first allocates excess transmission losses revenue to sub-regions of the Midwest ISO based on the actual losses incurred at the sub-regional level. The Midwest ISO then distributes excess transmission losses revenues to market participants based on their pro-rata share of the losses within their sub-regional area.[39]

The Midwest ISO and its stakeholders determined that the marginal losses methodology (and its associated sub-regional reimbursement mechanism) was the best way to assess market participants for the costs of transmission losses in their transactions. Since the Midwest ISO covers a vast geographical area with widely varying transmission losses, the use of marginal losses as a component of LMP was the most reasonable way to assess transmission losses on the users of the transmission grid. The marginal loss methodology and its associated reimbursement methodology was a reasoned compromise that correctly determined the cost of delivering the next increment of energy in the various regions, thus sending appropriate price signals, while also making sure that any excess losses that were

collected were appropriately reimbursed to the Market Participants using the transmission grid.

IV. Conclusion

Although Order No. 2000 gives general guidance for the development of RTO energy markets,[40] considerable work is required to tailor solutions to satisfy the unique needs of a region. Certain regions of the country, such as New York, New England, and the Mid-Atlantic previously enjoyed tight power pool operations, establishing a basis for the transition to an RTO. Other regions of the country, such as the Midwest, the Southeast, and the Pacific Northwest, have not experienced such a history of integrated operations, presenting a relatively greater challenge to RTO formation. In the Midwest, the geographic scope of the Midwest ISO added a further complicating factor in the development of an Order 2000-compliant RTO. It was crucial to the success of the Energy Markets that the Midwest ISO tackle such tough issues from the outset, working cooperatively with state regulators as a group, and equitably resolving all key market design issues in consultation with all stakeholders. Thanks to the extremely conscientious and dedicated work of all of the stakeholders, including the OMS, the Midwest ISO has demonstrated that creative solutions can be developed to meet the unique needs of a region by implementing Energy Markets that reflect the requirements of the region and also adhere to sound economic principles.■

Endnotes:

1. See http://www.midwestiso.org/emt/emt.shtml

2. The design of the Energy Markets has been discussed by the Midwest ISO and its stakeholders for over five years, dating back to the Midwest ISO's formation in 1998.

3. *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,145 (2003).

4. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (2004).

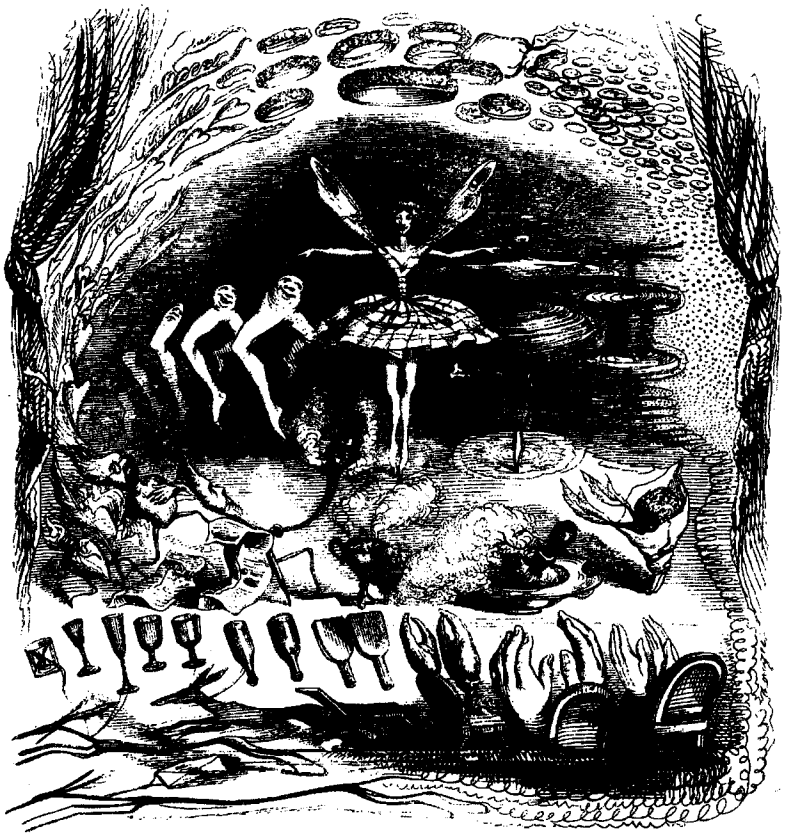
5. *See, e.g.*, filings made by the Midwest ISO in FERC Docket Nos. ER04-691, *et al.*, on Sept. 7, 2004, Oct. 5, 2004, Dec. 22, 2004, Jan. 7, 2005, Jan. 19, 2005, and Mar. 7, 2005.

6. The Apr. 1 date for start of market operations was approved by FERC in an order dated Feb. 17, 2005, and reiterated in an order issued on Mar. 16, 2005. *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,169 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,289 (2005).

7. Since over 400 GFAs totaling thousands of pages were analyzed, it took considerable time and effort for the Midwest ISO to conduct a detailed review of each GFA to determine what percentage of total Midwest ISO load the relevant GFAs would collectively represent in the Energy Markets.

8. *Midwest Indep. Transmission Sys. Operator, Inc.*, 107 FERC ¶ 61,191 (2004).

9. *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) ("Mobile"); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956) ("Sierra").



In the Midwest, the geographic scope of the Midwest ISO added a further complicating factor.

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10. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 at 137–139 (2004).

11. 108 FERC ¶ 61,236 at 105 and 266.

12. 108 FERC ¶ 61,236 at 142–143 and 149. The Commission also directed the carve-out of 30 GFAs (involving 2,198 MW) under which the provider of transmission services is not a public utility. 108 FERC ¶ 61,236 at para. 150. However, the Commission retained jurisdiction over any transmission service that the relevant transmission owners must take under the EMT to meet their obligations under such GFAs. *Id.*

13. Section 38.8.4 of the EMT addresses carved-out GFAs.

14. 108 FERC ¶ 61,236 at paras. 188–189, 192, 193–198, and Ordering Paras. (M) through (P).

15. Settlement Judge's Status Report dated Apr. 6, 2005 (at para. 3) in FERC Docket Nos. ER04-691-005, ER04-106-002 and EL04-104-004.

16. 108 FERC ¶ 61,163 at paras. 557 and 561.

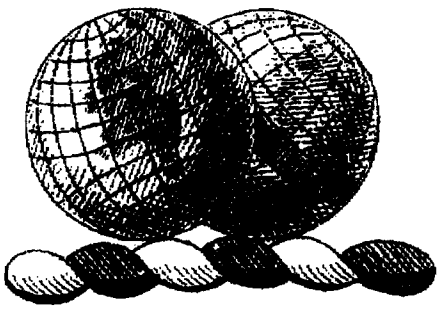
17. On Sept. 3, 2004, the OMS filed a request for rehearing of the Aug. 6, 2004 Order.

18. Order on Rehearing dated Sept. 30, 2004, *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,321 (2004).

19. On Feb. 17, 2005, the Midwest ISO submitted an informational filing that described the OMS proposal, the objections or concerns of other parties, and the Midwest ISO's alternative proposal regarding the access of state agencies to confidential information.

20. 18 C.F.R. § 35.34(k)(2) (2004). ("The Regional Transmission Organization must ensure the development and operation of market mechanisms to manage transmission congestion . . . The market mechanisms must accommodate broad participation by all Market Participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions.")

21. A comprehensive description of the history leading up to the development of the Midwest ISO's FTR allocation methodology can be found in the Midwest ISO's Jan. 31, 2005, filing with FERC in Docket Nos. ER04-691-022, *et al.* In addition to describing the results of the initial FTR allocation, the Midwest ISO's Jan. 31, 2005, filing gives an overview of the process undertaken to develop the FTR allocation methodology used by the Midwest ISO to allocate FTRs to Market Participants.



22. The details of the Midwest ISO's FTR allocation methodology can be found in Sections 42–46 of the EMT.

23. The results of the initial FTR allocation, including a description of how the "four-tier" allocation methodology worked, can be found in the Midwest ISO's Jan. 31, 2005, FERC filing in Docket Nos. ER04-691-022, *et al.*

24. The details of the four-tier process for nominating and allocating FTRs are embodied in Section 43.2 of the EMT.

25. See Section 43.2.5 of the EMT for a more detailed description of the "restoration allocation" process.

26. See Section 45 of the EMT.

27. See Section 43.4 of the EMT.

28. For more detailed statistics on the results of the Midwest ISO's initial allocation of FTRs, see the Midwest ISO's Jan. 31, 2005, FERC filing in Docket Nos. ER04-691-022, *et al.*

29. *Midwest Independent Transmission System Operator, Inc., et al.*, 108 FERC ¶ 61,163 at paras. 123 and 137–138 (2004).

30. Midwest Indep. Transmission Sys. Operator, Inc., 110 FERC ¶ 61,177 (2005).

31. See http://www.nerc.com/~filez/functionalmodel.html

32. http://www.midwestiso.org/meeting_agendas/cawg/01-19-04%20Draft%20of%20the%20Reliability%20Charter%20clean.pdf

33. Attachment B to the BA settlement contained a proposed tariff provision on "Limitations of Liability and Damages Regarding Control Area Operators." Pursuant to the directive of the Commission's Feb. 18 Order, the Midwest ISO's Mar. 21, 2005, compliance filing incorporated the proposed liability limitation provision into Section 10 of the EMT.

34. *Id.*

35. Attachment D to the BA settlement provided for "Recovery of Costs by Control Area Operators." The Commission required the Balancing Authorities to submit additional details about such costs in order to avoid any double-recovery. Feb. 18 Order at paras. 59 and 66. The Balancing Authorities were expected to submit such additional cost details on May 5, 2005.

36. Section 8 of BA Agreement.

37. Sections 13.2 and 13.3 of BA Agreement.

38. The methodology used by the Midwest ISO to calculate Marginal Losses in the Day-Ahead Energy Market can be found in Section 39.3.5 of the EMT, and the calculation of Marginal Losses for the Real-Time Energy Market is described in Section 40.4.1 of the EMT.

39. Surplus Marginal Losses are then returned to customers pursuant to the rules provided in Section 40.6 of the EMT.

40. *Regional Transmission Organizations*, Order No. 2000, FERC Stats & Regs. [Regs. Preambles 1996-2000] ¶ 31.089 (1999).