ORAL ARGUMENT HAS NOT YET BEEN SCHEDULED

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 04-1414
(consolidated with 05-1006, 05-1007, 05-1009, 05-1198, 05-1203, 05-1358, 05-1427, 05-1428, 05-1429)

WISCONSIN PUBLIC POWER, INC., *et al.*,
PETITIONERS,
v.
FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT.

ON PETITIONS FOR REVIEW OF ORDERS OF THE FEDERAL ENERGY REGULATORY COMMISSION

BRIEF FOR RESPONDENT FEDERAL ENERGY REGULATORY COMMISSION

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FINAL BRIEF: JANUARY 19, 2007

CIRCUIT RULE 28(a)(1) CERTIFICATE

A. Parties

The parties are as stated in the Petitioners' briefs.

B. Rulings Under Review:

Three groups of petitioners -- Midwest Transmission Dependent Utilities and Wisconsin Public Power Inc. ("Transmission Dependent Petitioners"), National Rural Electric Cooperative Association and Dairyland Power Cooperative ("Cooperative Petitioners"), and Duke Energy Shared Services, Inc. and Xcel Energy Services Inc. ("Transmission Owning Petitioners") -- seek review of 11 Commission orders:

1. *Midwest Independent Transmission System Operator, Inc.*, 107 FERC ¶ 61,191 (May 26, 2004) ("Procedural Order") (JA 1);

2. *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (Aug. 6, 2004) ("TEMT II Order") (JA 226);

3. *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236 (Sept. 16, 2004) ("GFA Order") (JA 342);

4. *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,157 (Nov. 8, 2004) ("TEMT II Rehearing Order") (JA 405);

5. *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,285 (Dec. 20, 2004) ("Compliance Order I") (JA 504);

6. *Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,049 (Jan. 24, 2005) ("Compliance Order II") (JA 514);

7. *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 (Apr. 15, 2005) ("GFA Rehearing Order") (JA 527);

8. *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,043 (Apr. 15, 2005) ("Compliance Order III") (JA 595);

9. *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,053 (Apr. 15, 2005) ("Compliance Order IV") (JA 625);

10. *Midwest Independent Transmission System Operator, Inc.*, 112 FERC ¶ 61,086 (July 22, 2005) ("Compliance Order V") (JA 636); and

11. *Midwest Independent Transmission System Operator, Inc.*, 112 FERC ¶ 61,311 (Sept. 9, 2005) ("GFA Rehearing Order II") (JA 643).

C. Related Cases:

These cases have not previously been before this Court or any other Court. The cases are related to a pending case, *East Kentucky Power Cooperative, Inc. v. FERC*, No. 06-1003 (D.C. Cir. filed Jan. 3, 2006), which pertains to tariffs filed by transmission owners to recover from customers certain charges (under Schedule 23) similar to charges (under Schedule 17) at issue here.

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Judith A. Albert
Senior Attorney

January 19, 2007

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GLOSSARY

I. Commission Orders Under Review

Compliance Order I	*Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,285 (Dec. 20, 2004)
Compliance Order IV	*Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,053 (Apr. 15, 2005)
Compliance Order V	*Midwest Independent System Operator, Inc.*, 112 FERC ¶ 61,086 (July 22, 2005)
GFA Order	*Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236 (Sept. 16, 2004)
GFA Rehearing Order	*Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 (Apr. 15, 2005)
Procedural Order	*Midwest Independent Transmission System Operator, Inc.*, 107 FERC ¶ 61,191 (May 26, 2004)
TEMT II Order	*Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (Aug. 6, 2004)
TEMT II Rehearing	*Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,157 (Nov. 8, 2004)

II. Other Orders

Declaratory Order	*Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 (2003)
ISO Formation Order	*Midwest Independent Transmission System Operator, Inc.*, 84 FERC ¶ 61,231 (1998)
Market Rules Order	*Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,280 (2003)

Opinion No. 453	*Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,033 (2001)
Opinion No. 453-A	*Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,141 (2002)
RTO Formation Order	*Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,326 (2001)
TEMT I Order	*Midwest Independent Transmission System Operator, Inc.*, 105 FERC ¶ 61,145 (2003)

III. Other Terms

ALJ	Administrative Law Judge
Cooperative Petitioners	Petitioners National Rural Electric Cooperative Association and Dairyland Power Cooperative
Energy Market Service	Energy Market Support Administrative Cost Recovery Adder
FPA	Federal Power Act
FTR	Financial Transmission Rights
FTR Service	Financial Transmission Rights Administrative Service Cost Recovery Adder
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
RTO	Regional transmission organization
Tariff	Open Access Transmission and Energy Markets Tariff which established Day 2 markets in the Midwest
Transmission Dependent Petitioners	Petitioners Midwest Transmission Dependent Utilities and Wisconsin Public Power Inc.

Transmission Owning Petitioners	Petitioners Duke Energy Shared Services, Inc. and Xcel Energy Services Inc.

IN THE UNITED STATES COURT OF APPEALS
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BRIEF FOR RESPONDENT FEDERAL ENERGY
REGULATORY COMMISSION

STATEMENT OF THE ISSUES

Three groups of petitioners seek review of a limited number of the dozens of issues addressed in eleven orders of the Federal Energy Regulatory Commission ("Commission" or "FERC"), approving the development of enhanced regional energy markets administered by the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). The issues they raise are as follows:

1. **Market power mitigation** – Whether the Commission properly declined to impose more stringent market mitigation measures, sought by some parties, when, in the Commission's judgment, the measures proposed by the Midwest ISO achieved the proper balance between tempering the exercise of market power and providing incentives for entry into the market. [Raised by Transmission Dependent Petitioners.]

2. **Cost allocation** – Whether the Commission reasonably determined that entities transacting under "grandfathered agreements," executed prior to the formation of the Midwest ISO in 1998, should pay Schedule 17 charges, when those charges pay the Midwest ISO's costs of providing Energy Market Services and all entities benefit from the Energy Markets. [Raised by Cooperative Petitioners.]

3. **Grandfathered agreements** – Whether the Commission's treatment of grandfathered agreements appropriately balanced the objectives of protecting the reliability of the markets, respecting the contractual relationships that the transmission owners relied upon when they agreed to create the Midwest ISO, and protecting the rights of other participants in the markets. [Raised by Transmission Owning Petitioners]

COUNTERSTATEMENT OF JURISDICTION

Transmission Dependent Petitioners contend, *see infra* page 54, that the Commission accepted a compliance filing that did not comply with its prior determination as to the appropriate marginal loss refund mechanism. As compliance proceedings on the appropriate marginal loss refund mechanism are still ongoing, the challenged orders are not final as to this one issue and the Court lacks jurisdiction to address it.

STATUTES AND REGULATIONS

The applicable statutes and regulations are contained in the Addendum to this brief.

STATEMENT OF THE CASE

I. Nature of the Case, Course of Proceedings, and Disposition Below

This case concerns the Open Access Transmission and Energy Markets Tariff ("TEMT" or "Tariff") filed by the Midwest ISO on March 31, 2004. The Tariff, which contains the terms and conditions necessary to implement a market-based congestion management program and energy spot markets, is a substantial step in the development of a regional energy market in the Midwest.

In 1998, the Commission approved the application of ten Midwestern transmission owners to transfer operation of their transmission facilities to an

Independent System Operator (the Midwest ISO).[1] In 2000, in its Order No. 2000, the Commission encouraged the formation of Regional Transmission Organizations ("RTOs") to improve reliability and competition in energy markets.[2] The Midwest ISO satisfied the criteria for RTO status in 2001.[3] FERC anticipated, however, that improvements to the ISO's congestion management method and market monitoring program would ensue. RTO Formation Order, 97 FERC at 62,513-14 and 62,518-19.

More than a year of stakeholder discussions, a technical conference, several Midwest ISO filings, and several Commission orders followed, resulting ultimately in the filing of the Tariff. That filing led to the eleven orders challenged here.

The issues addressed in these orders were numerous and difficult. Nevertheless, the scope of the appeals is relatively narrow. The appeals do not challenge the broad conceptual approach of the Tariff, nor are there challenges to dozens of specific issues addressed by the orders.

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

[2] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs., Regs. Preambles ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *dismissed sub nom. Public Utility District No. 1 of Snohomish County v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

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

The issues on appeal ultimately center on the Commission's balancing of the conflicting considerations and equities engendered by the market changes proposed under the Tariff. More specifically, Petitioners Midwest Transmission Dependent Utilities ("Midwest TDUs") and Wisconsin Public Power, Inc. (collectively, "Transmission Dependent Petitioners") contend that they: (1) are not adequately protected by the market power mitigation measures; and (2) have to pay too great a share of the cost of transmission losses. Petitioners Duke Energy Shared Services, Inc. and Xcel Energy Services, Inc. (collectively, "Transmission Owning Petitioners") object to the treatment of grandfathered agreements executed prior to the 1998 formation of the Midwest ISO, asserting that the Commission's approach improperly raises costs for market participants such as themselves. Petitioners National Rural Electric Cooperative Association and Dairyland Power Cooperative (collectively, "Cooperative Petitioners"), parties to grandfathered agreements, object to payment of Schedule 17 charges for Energy Market Services.

II. Statement of Facts

A. Regulatory Background

Section 201(b) of the Federal Power Act ("FPA"), 16 U.S.C. § 824(b), grants FERC exclusive jurisdiction over transmission and wholesale sales of electric energy in interstate commerce. Under FPA § 205(c), 16 U.S.C. § 824d(c), utilities must file tariff schedules with the Commission showing their rates and service terms, along with related contracts, for jurisdictional service. Upon receipt of such a filing, the Commission must assure that the rates and services are just and reasonable and not unduly discriminatory. *See* FPA § 205(a)-(b), 16 U.S.C. § 824d(a)-(b). The Commission may also institute investigations of existing rates on complaint or its own motion. *See* FPA § 206(a), 16 U.S.C. § 824e(a).

Under the *Mobile-Sierra* doctrine, "utilities may choose to voluntarily give up, by contract, some of their rate-filing freedom under section 205."[4] *Maine Public Utilities Comm'n v. FERC*, 454 F.3d 278, 283 (D.C. Cir. 2006) (citations omitted). Thus, parties may negotiate a fixed-rate contract with a provision relinquishing their right to file for a unilateral change in rates. *Id*. In that case, the Commission may abrogate or modify the rates only if required by the "public interest." *Id*. The "public interest" standard of review, while evading precise definition, is "much more restrictive than the just and reasonable standard of" FPA § 205. *Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 14 (D.C. Cir. 2002) (citing *Potomac Electric Power Co. v. FERC*, 210 F.3d 403, 407 (D.C. Cir. 2000)).

The underlying purpose of the *Mobile-Sierra* doctrine is "to preserve the benefits of the parties' bargain as reflected in the contract, assuming that there was no reason to question what transpired at the contract formation stage." *Id*. (citing *Town of Norwood v. FERC*, 587 F.2d 1306, 1312 (D.C. Cir. 1978)).

[4] *See United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956), and *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

B. Development of Regional Transmission Systems

Historically, electric utilities were vertically integrated monopolies, owning generation, transmission, and distribution facilities and selling these services as a "bundled package"' to customers in a particular geographical area. *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1363 (D.C. Cir. 2004) (explaining, generally, the development of regional electricity markets and, specifically, the Midwest ISO). In more recent years, however, driven by technological advances and legislative initiatives promoting increased entry into wholesale electricity markets, electric utilities increasingly "unbundled" their service offerings to their customers. This led to an increasingly competitive market for the sale of electric energy. *See New York v. FERC*, 535 U.S. 1, 5-14 (2002) (describing developments).

To foster these developments, so that the benefits of a competitive market are realized by customers, the Commission, in Order No. 888, directed utilities to offer non-discriminatory, open access transmission service.[5] To implement this

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[5] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1966) ("Order No. 888"), *clarified*, 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1997), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs., Regs. Preambles ¶ 31,048 ("Order No. 888-A"), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248, *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd sub nom. Transmission Access Policy Study Group v. FERC*,

directive, the Commission ordered the functional unbundling of wholesale generation and transmission services. *New York v. FERC*, 535 U.S. at 11. "Functional unbundling" requires each utility to state separate rates for its wholesale generation, transmission and ancillary services, and to take transmission of its own wholesale sales and purchases on a non-discriminatory basis under filed open access transmission tariffs. *Id*.

Order No. 888 also encouraged, but did not direct, the formation of independent system operators ("ISOs") to operate regional, multi-system transmission grids. *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730-32. The Commission announced various principles (e.g., ISO independence, control over grid operations, and responsibility for ensuring reliability of grid operations) that would guide its future assessment of ISO proposals.

After several years of experience reviewing initial ISO proposals, the Commission, in Order No. 2000, *see supra* page 4, directed all transmission owning utilities to make filings either to participate in an RTO or to explain efforts to participate in an RTO. The Commission explained that "better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation" was necessary to address regional

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225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

reliability concerns and to foster competition over wider geographic areas. *Midwest ISO Transm. Owners v. FERC*, 373 F.3d at 1364 (quoting rulemaking).

Order No. 2000 directed the utility members of a Commission-approved ISO (such as the Midwest ISO) to show, by January 16, 2001, that the ISO meets the minimum characteristics and functions of an RTO. Those characteristics and functions require the RTO, among other things, to be independent from market participants, to have planning and expansion authority, and to be the only provider of transmission services over the facilities it controls. *See* 18 C.F.R. §§ 35.34(j)-(k). The RTO also must ensure the development and operation of market-based mechanisms to manage congestion. While the Commission declined to prescribe a specific congestion pricing mechanism, it observed that markets based on locational marginal pricing and financial rights for firm transmission service "appear to provide a sound framework for efficient congestion management." Order No. 2000 at 31,126-27.

C. Development of the Midwest ISO

On January 15, 1998, ten Midwestern transmission owners applied for approval of: (1) the transfer of operational control of their transmission facilities to the Midwest ISO; and (2) an ISO-wide open access transmission tariff. The Commission conditionally approved the proposal, finding that it generally satisfied the Order No. 888 ISO formation principles. *See* ISO Formation Order at 62,138.

All new wholesale and existing unbundled retail transmission services began taking service immediately under the rates, terms and conditions of the open access tariff, while all existing bilateral agreements for wholesale loads ("grandfathered agreements" or "GFAs") would be placed under the tariff after a six-year transition period. *Id*. at 62,167 and 62,169-70. Certain rate issues were set for evidentiary hearing. *Id*. at 62,167.

On January 16, 2001 the Midwest ISO submitted a filing asserting that its current structure satisfied the RTO requirements. On December 20, 2001, the Commission conditionally granted the Midwest ISO RTO status. RTO Formation Order, 97 FERC at 62,500. The Commission found, *inter alia*, that the Midwest ISO's congestion management proposal was a "reasonable initial approach" to managing congestion for "Day 1" operation of an RTO, *see id.* at 62,513, but directed the ISO to develop a market-based approach to managing congestion for "Day 2" operations in order to improve the efficiency of the Midwest markets.[6] *Id*. at 62,522. Similarly, the Commission accepted the ISO's market monitoring plan with the proviso that the Commission would "periodically assess the need for, and degree of market monitoring." *Id*. at 62,519. The Commission also required

[6] "Day 1" refers to operations under the RTO as initially approved. "Day 2" refers to RTO operations as subsequently modified by the TEMT.

the Midwest ISO to file certain additional information pertaining to market monitoring. *Id*. at 62,518.

In a related proceeding addressing the rate matters set for hearing by the ISO Formation Order, the Commission affirmed an administrative law judge's finding that the "Schedule 10" cost of developing and running the Midwest ISO should be allocated to all market participants that benefit from the Midwest ISO's operations. Such beneficiaries, responsible for a share of the ISO's administrative costs, include parties to grandfathered agreements. *See Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,033 at 61,169 (2001) ("Opinion No. 453"). Because the RTO must be the only provider of transmission service over the facilities under its control, *id*. at 61,169-70, the Commission directed all transmission-owning members of the Midwest ISO to serve grandfathered agreement customers under the rates, terms and conditions of the Midwest ISO tariff. *See Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,141 at 61,413 (2002) ("Opinion No. 453-A"). (The Commission's determinations in Order No. 453 ultimately were affirmed by this Court in *Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1368).

D. Subsequent Events

On December 17, 2002, after over a year of stakeholder discussions, the Midwest ISO filed a petition for a declaratory order seeking the Commission's endorsement of its general approach to establishing Day 2 markets. On February 24, 2003, the Commission approved the general direction of the proposals, reserved judgment on some issues, and provided guidance on others. *Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 (2003) ("Declaratory Order"), *order on reh'g*, 103 FERC ¶ 61,210 (2003).

Meanwhile, on December 23, 2002, the Midwest ISO filed proposed Market Mitigation Measures (which presaged the Tariff mitigation measures at issue here). The Commission conditionally accepted the proposal on March 13, 2003, to be effective the later of December 1, 2003 or the first operation day of the Day 2 markets, and convened a technical conference to address the adequacy, interaction, and timing of certain of the market design elements. *Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,280 (2003) ("Market Rules Order"), *reh'g dismissed*, 105 FERC ¶ 61,147 (2003) ("Market Rules Rehearing Order").

On July 25, 2003, the Midwest ISO filed a proposed Tariff to implement Day 2 markets. Numerous parties protested and, after a stakeholder vote, the Midwest ISO filed a motion requesting withdrawal of the filing and additional guidance from the Commission. The Commission granted both requests. *Midwest Independent Transmission System Operator, Inc*., 105 FERC ¶ 61,145 (2003) ("TEMT I Order"), *reh'g dismissed*, 105 FERC ¶ 61,272 (2003). The Commission expected that this guidance, along with the guidance offered in contemporaneously-issued orders related to the Market Rules Order, *see* Market Rules Rehearing Order and *Midwest Independent Transmission System Operator, Inc.*, 105 FERC ¶ 61,146 (2003), would enable the Midwest ISO to file a complete version of the Tariff. TEMT I Order at P 3.

E. The Transmission and Energy Markets Tariff

On March 31, 2004, the Midwest ISO filed the revised Tariff at issue here. The Tariff contains the terms and conditions necessary to implement energy spot markets, *i.e.*, a Day-Ahead Energy Market and a Real-Time Energy Market. These are short-term markets in which a single market-clearing price is received by all generators bidding below that price and paid by all buyers bidding above that price. *Cf. Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 965 (D.C. Cir. 2005) (describing similar markets operated by the New York ISO).

The Tariff provides for “centralized security-constrained economic dispatch” on a regional basis. Under economic dispatch, the Midwest ISO orders generators to generate in merit order ("merit" meaning cheapest to most expensive). “Security-constrained” means that if the merit-ordered dispatch will cause a reliability (or some other) problem, the RTO will dispatch out-of-merit for the overall benefit of the transmission system.

The Tariff also includes a market-based congestion management program with locational marginal pricing and financial transmission rights ("FTRs"). Congestion occurs when requests for transmission service exceed the capability of the grid. Locational marginal pricing is a market-based method for managing congestion under which the energy prices at different nodes on the transmission grid reflect the cost of congestion. Under locational marginal pricing, the limited transmission capacity is used by the market participants who value it most highly, *i.e.*, are willing to pay a higher price.

Market participants may hedge against fluctuations in transmission congestion costs through FTRs. FTRs are financial instruments that entitle their holders to the difference in the locational marginal price between specified points on the transmission grid for a specified quantity of electricity. *Cf. Consumers Energy Co. v. FERC*, 367 F.3d 915, 921 (D.C. Cir. 2004) (describing FTRs). A transmission customer that uses a congested transmission path pays congestion costs to the Midwest ISO which, in turn, pays those costs to the holders of FTRs associated with that path. *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 139 (2004) ("TEMT II Order") (JA 226); *order on reh'g*, 109 FERC ¶ 61,157 (2004) ("TEMT II Rehearing Order") (JA 405), *order on reh'g*, 111 FERC ¶ 61,043 (2005) ("Compliance Order III") (JA 595), *order on reh'g*, 112 FERC ¶ 61,086 (2005) ("Compliance Order V") (JA 636).

Module D of the Tariff contains the market monitoring plan and market power mitigation measures, an initial version of which was accepted in the Market Rules Order. *See* discussion *supra* at 12. The purpose of the measures is to prevent a power seller who has market power during transmission congestion and high load conditions from driving prices from true scarcity levels to artificially inflated levels. Market Rules Order at P 9.

F. The Challenged Orders (Pricing Issues)

(1) Market Power Mitigation

As indicated above, during periods of transmission congestion and high load conditions, a power seller may acquire sufficient market power to drive prices to unreasonably high levels. Mitigation is imposed on entities in constrained areas that fail "conduct" and "impact" tests designed to show whether their conduct is significantly inconsistent with competitive outcomes (the conduct test) and, if so, whether the conduct results in a substantial change in one or more prices in the energy market (the impact test). TEMT II Order at P 245 (JA 262); *see Edison Mission Energy, Inc. v. FERC*, 394 F.3d at 965 (describing similar procedures used by the New York ISO).

The mitigation tests compare a seller's bid with the seller's "reference level." A reference level is based upon estimates of a generator's marginal costs, including legitimate risks and opportunity costs, and varies over a generator's output range, with an energy reference calculated for each 10-megawatt output segment for most units. TEMT II Order at P 299 (JA 270). When a bid fails the tests, it is mitigated (reduced) to the reference level. *Id*. at P 247 (JA 262).

The conduct and impact thresholds are different for "Broad Constrained Areas" and "Narrow Constrained Areas." A Broad Constrained Area is "an electrical area in which sufficient competition usually exists, even when one or more transmission constraints are binding, or into which the transmission constraints bind infrequently, but within which a transmission constraint can result in substantial locational market power under certain market or operating conditions." TEMT II Order at P 264 (JA 265). Broad Constrained Areas are not identified in advance. *Id*. When a transmission constraint becomes active, the Midwest ISO's Independent Market Monitor identifies the generators that are effective in managing the constraint and defines them to be in the Broad Constrained Area. *Id*. at P 265 (JA 265).

The Broad Constrained Area conduct threshold for energy offers is the lower of $100/megawatt-hour or 300 percent above a seller's reference price. *Id*. at P 308 (JA 271). If, after consultation between the supplier and the Independent Market Monitor, the latter determines that the bid fails the conduct test, the bid is subject to the impact test. The Broad Constrained Area impact threshold is the lower of $100/megawatt-hour or 200 percent above the market-clearing price. TEMT II at P 312 (JA 271).

A Narrow Constrained Area is "an electrical area defined by one or more transmission constraints that are expected to be binding for at least 500 hours during a given twelve month period, within which one or more suppliers is pivotal." *Id*. at P 276 (JA 267). A supplier is pivotal "when the output of some of its generation resources must be changed to resolve the transmission constraint during some or all of the hours when the constraint is binding." *Id*.

Narrow Constrained Areas are identified by the Midwest ISO's Independent Market Monitor on an annual basis, but can be identified more frequently as appropriate. *Id.* At the inception of the Midwest ISO energy markets on April 1, 2005, the Independent Market Monitor had designated two Narrow Constrained Areas, both in Wisconsin. *Id.* at P 293 (JA 269).

Because Narrow Constrained Areas are potentially more likely to be subject to the exercise of market power, more stringent thresholds for mitigation apply than in Broad Constrained Areas. *Id.* at P 277 (JA 267). The thresholds are intended to balance concerns that (1) locational market power could result in excessive market power costs if high region-wide thresholds are used, and (2) efficient economic signals must be established for new investment in generation and transmission in Narrow Constrained Areas. *Id.*; testimony of David B. Patton at 50 (R. 25, JA 830); *see also* TEMT II Order at P 309 (explaining calculation of thresholds) (JA 271).

On rehearing below, Transmission Dependent Petitioners contended that the economic withholding thresholds for Broad Constrained Areas are too generous and should be no larger than the lower of 50 percent or $25/megawatt-hour. The Commission denied the request, finding that the Tariff thresholds represented the appropriate balance between protection against exercise of market power and mitigation that could affect a generator's ability to receive appropriate revenue. TEMT II Rehearing Order at P 221 (JA 443).

Transmission Dependent Petitioners also objected to the definition and thresholds for Narrow Constrained Areas. Denying rehearing, the Commission emphasized that the difficulty in setting thresholds is to balance under-mitigation and over-mitigation. *Id*. at P 238 (JA 446). Setting thresholds too high (*i.e.*, under-mitigating) means that some exercise of market power will not be mitigated. Setting thresholds too low (over-mitigating) can decrease investment in needed infrastructure. *Id*. at P 238-39 (JA 446). The Commission also rejected an argument that Narrow Constrained Areas should be defined using a "collusion metric," finding that such a test, which is applied when a utility seeks market-based rate authority, is directed at a different purpose. *Id.* at P 241-43 (JA 447).

(2) Marginal Losses

"Transmission losses refer to the amount of electric energy lost when electricity flows across a transmission system." *Sithe/Independence Power Partners, L.L.P. v. FERC*, 285 F.3d 1, 3 (D.C. Cir. 2002). Generally, the amount of the loss is primarily a function of the distance the electricity travels, with the loss increasing as the distance traveled increases. *Id*. A public utility that purchases energy must pay for these losses as part of its transmission rate.

Historically, Commission precedent required transmission losses to be determined on an average system-wide basis and their costs allocated to customers on a *pro rata* basis. *Id*. at 3. More recently, RTOs have begun to use marginal losses. "In a large geographic area, such as the Midwest ISO footprint, losses can be significant, and pricing them on a marginal basis is important to establishing nodal prices that accurately reflect the cost of supplying additional load at each node." Declaratory Order at P 31. These accurate signals help to bring about "a least-cost dispatch that reflects the true costs of transmission." TEMT II Order at P 71 (JA 237).

Marginal losses, however, typically exceed average losses, so the Commission directed the Midwest ISO to develop a mechanism to return surplus revenues to its customers in an equitable way. Declaratory Order at P 56. In response, the Midwest ISO proposed to redistribute the excess revenue on an hourly basis to "loss pools," and from the loss pools to market participants on a *pro rata* basis. TEMT II Order at P 66 (JA 237).

A number of parties protested the transition from average loss charges to marginal loss pricing. *Id.* at P 67-70 (JA 237). To give market participants more time to adjust to the marginal loss approach, the Commission directed the Midwest ISO to file a transitional marginal loss surplus refund method within 60 days. *Id*. at P 73-75 (JA 238). The transitional mechanism permits market participants to pay the lower of marginal losses or their (historical) average losses for a five-year transition period. *Id.*

The Commission accepted the Midwest ISO's proposed marginal loss mechanism, finding that it essentially fit the Commission's prior guidance that the ISO should implement marginal loss pricing as a means to achieve least-cost dispatch. *Id*. at P 66, 225-38 (JA 237, 259-60). However, as the detail in the Tariff filing was not sufficient "to allay the concerns of some market participants" that they would incur significant marginal loss charges, the Commission directed the Midwest ISO, after consultation with stakeholders, to address these concerns by making a revised filing within 270 days from market start. *Id*. at P 239 (JA 261).

On October 5, 2004, the Midwest ISO made the 60-day transitional refund compliance filing and proposed a refund method based on Balancing Authority Areas, rather than through previously proposed loss pools. *Midwest Independent*

Transmission System Operator, Inc., 109 FERC ¶ 61,285 at P 160 (2004) ("Compliance Order I") (JA 504). The Transmission Dependent Petitioners protested, contending that this methodology would divert refunds from the market participants who disproportionately fund it to other market participants who happen to reside in the same control area. *Id*. at P 165 (JA 510). The Commission accepted the proposal, finding it "consistent with our intentions with respect to not exposing participants to charges different than their average actual losses." *Id.* at P 171 (JA 511). Nevertheless, the Commission expressed concern that market participants (such as the Transmission Dependent Petitioners) with generation distant from load might not receive a sufficient refund share, and directed the Midwest ISO to explain its method for determining marginal loss surpluses for these entities. *Id.* at P 172-73 (JA 511).

The Midwest ISO submitted a filing January 21, 2005 to comply with the Compliance Order I directive, and the Transmission Dependent Petitioners again objected. *Midwest Independent Transmission System Operator, Inc*., 111 FERC ¶ 61,053 at P 41 (2005) ("Compliance Order IV") (JA 631). In Compliance Order IV, the Commission addressed the January 21, 2005 filing and the requests for rehearing of Compliance Order I. Accepting the filing, the Commission found that the Midwest ISO had complied with Compliance Order I, that it is not possible to return loss surpluses on an individual transaction basis, and that losses must be refunded on an aggregate basis that avoids cross-subsidies to the extent possible. Compliance Order IV at P 46-50 (JA 632).

The Commission also required the Midwest ISO to make an informational filing that provides data on losses based on the first six months of market experience. *Id.* at P 51-52 (JA 632-33). The ISO was required "to submit a proposal for redressing any identified cross-subsidies, and ensuring that market participants are not exposed to losses that exceed average or actual losses in a filing that includes proposed tariff language. *Id.* Both filings were due 270 days after market start.

The Transmission Dependent Petitioners sought rehearing, which the Commission denied. Compliance Order V at P 16-19 (JA 638-39). The Midwest ISO made further filings on December 27, 2005 and on March 27, 2006, as supplemented on June 8, 2006. On November 1, 2006, the Commission issued an order addressing these filings and directing a further Midwest ISO filing. *Midwest Independent Transmission System Operator, Inc*., 117 FERC ¶ 61,142 (2006) ("November 1, 2006 Order").

G. The Challenged Orders (Grandfathered Agreement Issues)

(1) Consideration and Treatment of Grandfathered Agreements

The Tariff filing presented the Commission with the difficult issue of the appropriate treatment of the approximately 300 grandfathered agreements

("GFAs") in effect in the Midwest ISO region. GFAs are "agreements executed or committed to prior to September 16, 1998 . . . that are not subject to the specific terms and conditions of the [Tariff] consistent with the Commission's policies." *Midwest Independent Transmission System Operator, Inc.*, 107 FERC ¶ 61,191 at P 15 (2004) ("Procedural Order") (citing Tariff section 1.126) (JA 3), *order on reh'g*, *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 (2005) ("GFA Rehearing Order") (JA 527). As explained *supra* at 10, a GFA customer takes transmission service under the terms of its grandfathered agreement from its service provider, which takes service under the Tariff to fulfill its GFA obligations.

The Midwest ISO stated that grandfathered agreements, each specifying its own scheduling and other transaction terms, affected up to 40 percent of the total load in the region. The ISO contended that continuing the special six-year transitional transmission scheduling rights to grandfathered agreement holders would require a "carve-out" of transmission capacity. "Carving out" means that the GFA parties "are allowed to exercise the scheduling and energy management provisions of their GFAs in the same manner they did before the Energy Markets started." *Midwest Independent System Operator, Inc.*, 108 FERC ¶ 61,236 at P 90 (2004) ("GFA Order") (JA 342), *order on reh'g*, GFA Rehearing Order at P 52 (JA 536). Transactions in the Energy Markets would have to be scheduled around this reservation, and that would negatively impact the ISO's ability to reliably operate the Energy Markets and place an excessive financial burden on other market participants. Procedural Order at P 15 (citing Midwest ISO Transmittal Letter at 9 (R. 25, JA 3).

The Midwest ISO proposed to allow parties to convert their grandfathered agreements to agreements under the Tariff, and to require parties that did not convert their grandfathered agreements to select one of three scheduling and settlement options. *Id*. P at 19 (JA 4). The three options were intended to preserve financial rights under the grandfathered agreements so that parties to such agreements would remain financially indifferent to the treatment of their transactions in the Energy Markets. Midwest ISO Transmittal Letter at 9 (R. 25, JA 664). Nevertheless, although the grandfathered agreements would remain financially indifferent, their transactions would be scheduled pursuant to the terms of the Tariff.

The Midwest ISO contemplated that parties to grandfathered agreements would designate a GFA Responsible Entity and a GFA Scheduling Entity. The GFA Responsible Entity, "which must be a Market Participant under the TEMT, will be financially responsible for Market Activities charges, Schedule 16 and 17 charges, Transmission Usage Charges and debits or credits associated with FTRs held by the GFA Responsible Entity." Procedural Order at P 19 n.23 (citing Tariff section 38.8.1, Original Sheet No. 443) (JA 4). The GFA Scheduling Entity – "which can be the GFA Responsible Entity or its agent – will submit bilateral transaction schedules under the TEMT for sales or purchases of energy under the GFA." *Id.* P 19 n.24 (citing Tariff section 38.8.2, Original Sheet No. 444) (JA 4). *See also id.* P 20-22 (describing responsibilities of GFA Responsible Entity and GFA Scheduling Entity) (JA 4-5).

On May 26, 2004, the Commission instituted an investigation to enhance its understanding of the grandfathered agreements. *Id.* at P 51 (JA 9). The Commission would then be better able to balance the potentially conflicting goals of preserving the grandfathered agreements, preserving the bargain that many transmission owners relied upon in creating the Midwest ISO, developing a market-based congestion management system, and minimizing cost shifts caused by the grandfathered agreements. *Id*. at P 65-66 (JA 12); GFA Rehearing Order at P 81 (JA 541).

The Procedural Order established a three-step process. In Step 1, the Commission required jurisdictional public utilities providing or taking service under grandfathered agreements to submit information about that service and the governing grandfathered agreement. The Commission directed utilities to indicate, as part of the information collected, whether any modification to the grandfathered agreement is subject to a "just and reasonable" standard of review or a *Mobile-*

Sierra "public interest" standard of review. Procedural Order at P 68 (JA 12); *see supra page* 5-6 (discussing standards). The Commission also required the Midwest ISO to "provide additional information as to the reliability and economic benefits of its proposed congestion management system." *Id*. at P 72 (JA 13).

In Step 2, the Commission set for trial-type hearing before two presiding Administrative Law Judges ("ALJs") those grandfathered agreements for which the parties could not agree on the information required in Step 1. The ALJs presented the results of the hearing in a report to FERC on July 28, 2004. *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 63,013 (2004) (JA 103). *See also* GFA Order at P 106 (JA 360). As further detailed *infra*, the Commission ruled on the issue of whether and how the grandfathered agreements could function in the GFA Order, which was Step 3 of the investigation. *Id.* at 107 (JA 360). *See also* Procedural Order at P 78 (JA 14).

(2) "Carve Out" of Certain Grandfathered Agreements

The fact-finding investigation found that 229 grandfathered agreements would be in effect at the start of the Energy Markets, representing 25,000 megawatts of transmission service (23 percent of total Midwest ISO load). GFA Order at P 4 (JA 343). Of the 229, 52 grandfathered agreements, representing approximately 9,700 megawatts (9 percent of total Midwest ISO load), would participate in the Energy Markets as a result of the parties' voluntary election. *Id*.

Approximately 5,000 additional megawatts (4.5 percent of the total) were represented by 50 grandfathered agreements subject to unilateral modification under the just and reasonable (rather than the *Mobile-Sierra* public interest) standard. *Id*. The Commission found that the proposed Tariff does not rewrite grandfathered agreements, although it imposes changes to the way in which transmission service is provided. To the extent that this caused cost shifts between GFA parties, the agreements could be renegotiated. *Id*. at P 138 (JA 364-65).

This left relatively few grandfathered agreements, only 127, representing 10,385.2 megawatts. These agreements included: (1) grandfathered agreements explicitly subject to the *Mobile-Sierra* public interest standard of review; (2) grandfathered agreements that are silent on the standard of review; and (3) grandfathered agreements under which the entity providing service is not a Commission-jurisdictional public utility. *Id*. at P 135, 141 (JA 364, 365). After examining the record evidence, the Commission concluded that the Midwest ISO could reliably operate the Day 2 Energy Markets with this relatively small number of grandfathered agreements carved out from Tariff scheduling. *Id.* at P 89-98 (JA 356-58). Moreover, although carving out would decrease Energy Market efficiency, Day 2 aggregate costs should still be less than under the Day 1 market. *Id.* at P 100 (JA 358-59).

On rehearing, Xcel Energy argued that parties had not received a meaningful opportunity to evaluate the grandfathered agreement information. GFA Rehearing Order at P 61 (JA 537). Cinergy (now Duke Energy) argued that failure to include grandfathered agreements in the Day 2 market results in undue discrimination against nonparties and will undermine gains in reliability and efficiency for the Midwest ISO market. *Id.* at P 71-74 (JA 539-40). The Commission denied both rehearing requests. *Id.* at P 64-67 (addressing procedural issues), P 81-100 (addressing treatment of grandfathered agreements) (JA 538, 541-44).

(3) Charges Under Schedules 16 And 17

The Midwest ISO initially filed proposed Schedules 16, Financial Transmission Rights Administrative Service Cost Recovery Adder ("FTR Service"), and 17, Energy Market Support Administrative Service Cost Recovery Adder ("Energy Market Service"), on September 24, 2002 in Docket No. ER02-2595-000. The schedules were refiled, with some differences, as part of the Tariff. Both the GFA Order and an order issued on the same day in Docket No. ER02-2595-000 addressed these schedules. *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235 (2004) ("Schedule 16/17 Order") (JA 329), *order on reh'g*, 111 FERC ¶ 61,051 (2005).

Schedule 16 is intended to recover the costs associated with implementing and administering FTR Service from FTR owners. All customers who hold FTRs to hedge against congestion charges are subject to Schedule 16 charges. Schedule 16/17 Order at P 27-28 (JA 333-34); GFA Order at P 294 (JA 389). Customers taking service under carved-out grandfathered agreements, however, are not assessed Schedule 16 charges because they are not subject to congestion charges and thus have no need for FTR Service. GFA Order at P 295 (JA 389).

Energy Market Service supports the day-ahead and real-time energy markets through which participants offer to sell and bid to buy energy. *See* Schedule 16/17 Order at P 29 (enumerating main activities making up Energy Market Service) (JA 334). The Cooperative Petitioners argued that entities acquiring power through long-term contracts should not have to pay Schedule 17 charges because they arrange their purchases and sales without a centralized market. *Id.* at P 33, 36 (JA 335); GFA Rehearing Order at P 166 (JA 554). The Commission disagreed, finding that the Energy Markets benefited all entities transacting over the grid, including entities such as Cooperative Petitioners who do not actually use or take Energy Market Service. Schedule 16/17 Order at P 43-51 (JA 336-38); GFA Order at P 298 (JA 389).

(4) Designation of the GFA Responsible Entity and the GFA Scheduling Entity

Step 1 of the grandfathered agreement investigation required grandfathered parties to submit the names of the GFA Responsible Entity and GFA Scheduling Entity. Where parties were unable to agree, the ALJs made the determinations.

GFA Order at P 151-52, 163 (JA 367). Like the ALJs, the Commission found that the GFA Responsible Entity should be the transmission owner responsible for providing transmission service under the grandfathered agreement. *Id.* at P 161 (JA 368). This is consistent with Opinion No. 453, which requires the transmission owner or ITC Participant to take transmission service under the Midwest ISO Tariff in order to satisfy its GFA obligations, and with precedent concerning the pass through of costs under other regional transmission provider tariffs. *Id*. at P 161-62 (JA 368-69); GFA Rehearing Order at P 148 (JA 551).

The Commission also affirmed ALJ findings that the GFA Scheduling Entity, where the GFA parties did not agree upon a designation, must be either the GFA Responsible Entity or its designated agent. GFA Order at P 165 (JA 369). Since "the GFA Responsible Entity is financially responsible for the market impact costs of GFA transactions, then [it] must have the final say on the schedule it submits into the Day-Ahead Energy Market for that transaction." *Id.*

SUMMARY OF ARGUMENT

I. Response to Transmission Dependent Petitioners

The Commission reasonably concluded that the market mitigation measures achieved the proper balance between tempering the exercise of market power and providing incentives for new entries into the market. Mitigation measures that are too loose mean that some exercise of market power will not be mitigated. Mitigation measures that are too strict, however, may result in too frequent interventions into the market, decreasing market confidence and investment in needed infrastructure, and increasing reliability problems. The mitigation measures approved by the Commission for Midwestern markets (both "broad" and "narrow") are similar to those in effect in other regional markets, and are well within the range of what is just and reasonable.

Moreover, the Independent Market Monitor is empowered to identify market problems and, based on actual results, to recommend modifications to market rules if necessary. The Commission has also imposed ongoing reporting requirements which will help ensure that the mitigation measures continue to provide the proper level of market mitigation.

II. Response to Cooperative Petitioners

The Commission's conclusion that transactions under grandfathered agreements should be subject to Schedule 17 charges was reasonable. Schedule 17 charges cover the Midwest ISO's costs of providing Energy Market Service. The markets provide universal benefits, including a more reliable transmission grid, clear price signals for better infrastructure siting, and price transparency, to all market participants. As all entities who use the grid benefit from the markets, all should pay a share of the administrative costs of operating them.

III. Response to Transmission Owning Petitioners

The Commission's approval of the treatment of grandfathered agreements was reasonable. The agreements, which generally contain terms of service incompatible with the terms of the Tariff, represented a serious obstacle to initiation of the Midwest ISO Energy Markets. Their accommodation required balancing of sometimes competing objectives. These objectives included achieving the needed reliability and efficiency benefits to the grid that would result from a market-based congestion management system; preserving the grandfathered agreements for a transition period, as the transmission owners agreed to (and the Commission approved) when the owners voluntarily formed the ISO; respecting the contractual rights between the parties to the grandfathered agreements; and ensuring that the costs of the new markets are reasonably apportioned. The Commission's balancing of these objectives was reasonable, the Energy Markets are functioning, and all entities who use the transmission grid benefit now, and will continue to benefit in the future, from infrastructure improvements.

Development of a market-based congestion management system would provide needed improvements in the reliability and efficiency of the transmission grid. While integration of the grandfathered agreements into the energy markets would enhance that reliability and efficiency, part of the bargain struck initially when the transmission owners voluntarily formed an ISO was that the grandfathered agreements would be maintained. The Commission thus reasonably sought to preserve that bargain.

ARGUMENT

I. Standard of Review.

The Court reviews FERC orders under the Administrative Procedure Act's arbitrary and capricious standard. *See e.g.*, *Sithe/Independence Power Partners v. FERC*, 165 F.3d 944, 948 (D.C. Cir. 1999). The relevant inquiry for a court under that standard is whether the agency has "examine[d] the relevant data and articulate[d] a rational connection between the facts found and the choice made." *Motor Vehicle Manufacturers Ass'n v. State Farm Mutual Automobile Ins. Co.*, 463 U.S. 26, 43 (1983). The level of a court's "surveillance of the rationality of agency decisionmaking, however, depends upon the nature of the task assigned to the agency." *Nat'l Cable Television Ass'n v. Copyright Royalty Tribunal*, 724 F.2d 176, 181 (D.C. Cir. 1983). "Because [i]ssues of rate design are fairly technical, and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission, our review of whether a particular rate design is just and reasonable is highly deferential." *Northern States Power Co. v. FERC*, 30 F.3d 177, 180 (D.C. Cir. 1994) (internal quotation marks and citations omitted). *See also Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1368 (quoting *Association of Oil Pipe Lines v. FERC*, 83 F.3d 1424, 1431 (D.C. Cir. 1996) ("When FERC's orders concern ratemaking, we are 'particularly deferential to the Commission's expertise.'")).

Here, the Commission reasonably approved a complex and comprehensive package of initiatives, developed by the Midwest ISO after consultation with market participants, and proposed in a series of filings with the Commission. Dozens of parties participated in Commission proceedings to review these filings. No party challenges the Midwest ISO's broad objectives, or the Commission's approval of the Tariff and the Energy Markets as a whole. Rather, parties are generally supportive of the Midwest ISO's efforts to improve the efficiency, competitiveness and reliability of the regional energy markets it administers. *See* GFA Order at P 100 (finding that implementing the Tariff will expand the use of economic dispatch, lower aggregate costs and increase overall market efficiency) (JA 358-59). A few, however, persist in raising objections to certain details of the proposal.

II. The Commission Reasonably Found That the Midwest ISO's Proposals for Market Power Mitigation Were Appropriate.

A fundamental goal of the Commission for the electric industry as a whole is to foster the development of competitive markets. *See, e.g.*, *Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1364. Narrow Constrained Areas, however, by definition are more likely than other areas to be subject to the exercise of market power abuse. Consequently, market power mitigation policies for Narrow Constrained Areas must be carefully crafted to both temper the exercise of market power and to provide incentives for new entry (by permitting suppliers operating in Narrow Constrained Areas to make a profit). For these reasons, the Commission carefully evaluated the Midwest ISO's market monitoring and market power mitigation proposals before finding them just and reasonable. TEMT II Rehearing Order at P 232-44 (JA 445-47). *See also supra* page 15-18 (explaining approved "conduct" and "impact" test for market power mitigation in both Broad and Narrow Constrained Areas).

Transmission Dependent Petitioners "do not challenge FERC's policy choices" (Br. at 22), including the Commission's acceptance of the proposed market monitoring and mitigation program in general. Instead, they contend that the Commission did not get all of the details of the program quite right. Their arguments are unavailing. *See Edison Mission Energy, Inc. v. FERC*, 394 F.3d at 969 (agency's responsibility, in approving market mitigation measures, is to ensure that measures "will do more good than harm") (quoting *Maryland People's Counsel v. FERC*, 761 F.2d 780, 788-89 (D.C. Cir. 1985)).

A. The Commission's Approval of the Midwest ISO's Definition of "Narrow Constrained Area" Was Reasonable.

Transmission Dependent Petitioners challenge the use of a single-supplier measure of market power (the pivotal supplier test) to identify Narrow Constrained Areas (Br. at 25), and argue that a concentration metric (such as the Herfindahl-Hirschman Index) should also be used to determine whether multiple suppliers can jointly exercise market power when transmission is constrained. In support, they contend (Br. at 25-26) that: (1) the Commission's analysis of applications for market-based rate sales authority (as set forth in *AEP Power Mktg.*, 107 FERC ¶ 61,018 (2004), *reh'g denied*, 108 FERC ¶ 61,026 (2004), and other cases) employs both a unilateral measure of market power and a concentration metric; and (2) the test approved in the challenged orders is inconsistent with an approach taken in a later Commission proceeding.

(1) The Market-Based Rates Framework Is Not Appropriate For the Identification of Narrow Constrained Areas.

As the challenged orders explain, the Commission's market-based rate framework is not appropriate for determining Narrow Constrained Areas. *See* TEMT II Rehearing Order at P 242-43 & n.181 (JA 447). The Midwest ISO's market monitoring and mitigation proposal does not evaluate whether individual suppliers have market power, as the Commission does under the market-based rate framework. Rather, the Tariff defines when and how market power mitigation should take place in certain geographic areas of the transmission grid, based on the risk that market participants in that area will exercise market power. As such, the Commission properly considered Transmission Dependent Petitioners' proposal in light of the need to balance curbs on market power with incentives to enter the market. It found that the use of the Herfindahl-Hirschman Index that Transmission Dependent Petitioners' favored could result in over-mitigation, and accordingly, it reasonably rejected the proposal. TEMT II Order at P 283 (JA 268).

The Commission's market-based rate evaluation framework and the Midwest ISO's market power mitigation program "differ both in the definitions they use and in how they are applied." TEMT II Rehearing Order at P 242 (JA 447). The Commission's market-based rate evaluation framework evaluates pivotal suppliers based on the control area's annual peak demand, *AEP Power Marketing*, 107 FERC ¶ 61,018 at P 36, whereas a Narrow Constrained Area is defined by transmission constraints that can exist at any time, not just at peak. TEMT II Order at P 276 (JA 267). *See also supra* page 17-18 (describing Narrow Constrained Areas). For Narrow Constrained Areas, "a pivotal supplier is defined as being able to affect a transmission constraint, and a variety of conditions including peak and non-peak are considered, unlike in the Market Based Rates pivotal supplier test. Non-pivotal suppliers may be found to be in [a Narrow Constrained Area], because only one supplier, not all, within the area would need to be found to be pivotal." TEMT II Rehearing Order at P 242 n.181 (JA 447).

To screen for generation market power under its market-based rates policy, the Commission uses a pivotal supplier analysis (based on a control area's annual peak demand) and a market share analysis (applied on a seasonal basis). *AEP Power Marketing*, 107 FERC ¶ 61,018 at P 36. Failing either screen establishes a rebuttable presumption that a generator has market power; passing both screens establishes a rebuttable presumption that it does not. *Id.* at P 37. Under the

Midwest ISO's market power mitigation program, "if the area meets the definition for [a Narrow Constrained Area], [Narrow Constrained Area] mitigation will not be automatically applied, but the generator will be subject to conduct and impact tests" – that is, its transactions will be monitored for the possible exercise of market power. TEMT II Rehearing Order at P 242 (JA 447). In light of the fact that the Tariff does not allow generators to rebut the Independent Market Monitor's finding (using the pivotal supplier test) that they are within a Narrow Constrained Area, and therefore subject to the conduct and impact tests, *see* TEMT II Order at P 276-77 (JA 267), one could argue that the Midwest ISO's market power mitigation program is stricter than the Commission's market-based rates evaluation framework. Adding a concentration metric to help identify Narrow Constrained Areas would detect – and automatically implement conduct and impact screening in – other areas of the grid, including concentrated markets where there is sufficient capacity and mitigation is not appropriate. TEMT II Order at P 283 (JA 268). Because adding the concentration metric to the Midwest ISO's analysis would result in over-mitigation, it was therefore reasonable for the Commission to reject Transmission Dependent Petitioners' proposal that the Midwest ISO utilize this second screen to help identify Narrow Constrained Areas.

For all these reasons, as the Commission explained in the challenged orders, the market-based rates policy is not appropriate precedent for defining NCAs. *See*

Florida Municipal Power Agency v. FERC, 315 F.3d 362, 368 (D.C. Cir. 2005) (task for reviewing court is not whether Petitioner's approach is reasonable, but whether agency's approach is reasonable and supported by the record).

(2) The Later PJM Proceeding Is Not Relevant.

Transmission Dependent Petitioners next argue that the Commission has required PJM Interconnection, L.L.C. ("PJM"), a neighboring regional transmission organization, to justify its approach to defining areas for market power mitigation in light of the Commission's use of both unilateral and coordinated market power metrics under its market-based rate policy. Br. at 26-27 (citing *PJM Interconnection, LLC*, 110 FERC ¶ 61,053 (2005) ("PJM Order")). However, the PJM Order, issued after the TEMT II and TEMT II Rehearing Orders, is irrelevant. Agencies normally "need not explain alleged inconsistencies in the resolution of subsequent cases." *CHM Broadcasting Ltd Partnership v. FCC*, 24 F.3d 1453, 1459 (D.C. Cir. 1994); *see also Jeff MacLeod v. ICC*, 54 F.3d 888, 892 (D.C. Cir. 1995) (declining to "reach out" to a decision made after the one actually under review); *Altamont Gas Transmission Co. v. FERC*, 965 F.2d 1098, 1101 (D.C. Cir. 1992) (finding that a later decision cannot retroactively invalidate a decision that was sound when made).

While there can be an exception to this rule where the later case is part of "arguably inconsistent decision-making," *Idaho Power Co. v. FERC*, 312 F.3d

454, 464 (D.C. Cir. 2002), that exception is inapplicable here, where the Midwest ISO modeled its mitigation measures after those previously approved for neighboring ISOs in New York and New England. *See* Market Rules Order at P 20. The exception for a significant change in Commission policy, *Williston Basin Interstate v. FERC*, 165 F.3d 54, 61-62 (D.C. Cir. 1999), is inapplicable for similar reasons.

Even if the later PJM Order were relevant (and it is not), Transmission Dependent Petitioners neglect to mention that the Commission, while it accepted PJM's proposed collusion metric, nevertheless instituted an FPA § 206 investigation to determine whether that approach was, in fact, reasonable. PJM Order at P 83, 87. The parties ultimately settled and FERC approved the settlement without deciding any "principle or issue." *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,076 (2006).

The PJM Order is therefore an inappropriate yardstick by which to measure the Commission's analysis of the Midwest ISO's proposal. At best, it demonstrates that there may be more than one approach to identifying constrained areas of the transmission grid. This is entirely appropriate; as the Commission has found, it is not necessary for all RTOs to take the same approach to market and rate design. TEMT II Rehearing Order at P 219 (JA 443). There is a range of what is just and reasonable. *See, e.g.*, *FPC v. Conway Corp.*, 426 U.S. 271, 278 (1976);

Montana-Dakota Util. Co. v. Northwestern Pub. Serv. Co., 341 U.S. 246, 251 (1951). The Commission reasonably found, as explained elsewhere in this brief, that the Midwest ISO's market power mitigation proposal fell within that range.

(3) The Independent Market Monitor Can Make Further Adjustments.

Although the Commission declined to require the Midwest ISO to define Narrow Constrained Areas in terms of a coordination metric such as the Herfindahl-Hirschman Index, it encouraged the Independent Market Monitor to make use of such a metric. The Commission noted that there could be areas in which the HHI is high (suggesting an insufficient number of suppliers in the market), but there is excess capacity (*i.e.*, sufficient supply). TEMT II Order at P 283 (JA 268). It held that, in such circumstances, "it is more important to look at which supplier or suppliers are essential to meeting the market's needs than what the [Herfindahl-Hirschman Index] is;" for this reason, it encouraged the Independent Market Monitor to monitor areas where the Herfindahl-Hirschman Index is high and suppliers may be jointly pivotal. *Id.* at P 283 (JA 268).

The Midwest ISO's proposal – and the Commission's orders accepting it – also afford the Midwest ISO and its Independent Market Monitor flexibility in continuing to identify Narrow Constrained Areas. The Independent Market Monitor will identify such areas annually, and may do so more often as needed. *Id.* at P 276 (JA 267). Intervenors, including Transmission Dependent Petitioners, may request that the Independent Market Monitor consider additional flowgates in its analysis of potential Narrow Constrained Areas. *See id.* at P 298 (JA 270).

Further, the Tariff requires the Midwest ISO and the Independent Market Monitor to identify problems in the market, and it empowers the Independent Market Monitor to recommend to the Midwest ISO modifications to market rules – which would include those used to identify Narrow Constrained Areas. *Id.* at P 261 (JA 264). The Commission explained that it expects the Midwest ISO and the Independent Market Monitor "to use this authority to further refine the tariff . . . by identifying further and more precise conduct and criteria that may be inappropriate and that may have an unacceptable impact upon the markets . . . ." *Id.* And ongoing reporting requirements will help the Commission ensure that the method of identifying Narrow Constrained Areas remains just and reasonable. *See, e.g.*, *Environmental Action v. FERC*, 996 F.2d 401, 406, 410-12 (D.C. Cir. 1993) (ordering quarterly transaction reports and providing for market monitoring and mitigation offsets the potential for abuses of market power); *Consumer Federation of America v. CPSC*, 990 F.2d 1298, 1307 (D.C. Cir. 1993) ("Critical to our decision, the Commission has undertaken . . . to monitor the Consent Decree's 'effectiveness'" and can consider other measures if the approved approach proves to be ineffective).

B. The Commission's Approval of the Mitigation Thresholds for Narrow Constrained Areas Was Reasonable.

Narrow Constrained Areas are potentially more subject to the exercise of market power than are other areas, and, consequently, FERC approved more stringent thresholds for mitigation for them. TEMT II Order, P 246 (JA 262). The need for market power mitigation, however, must be balanced with incentives for new entry of generation and transmission capacity into the market. *Id.*, P 277 (JA 267). Setting thresholds too high (and thus under-mitigating the market) means that an exercise of market power may not be mitigated. TEMT II Rehearing at P 238 (JA 446). Setting thresholds too low "results in over-mitigation, which could lead to more frequent intervention in the market, and that some competitive market results will be mitigated, decreasing market confidence and, therefore, investment in needed infrastructure." *Id*. Over-mitigation also means that generators will not be able to recover their costs, "and generators may exit the market, or be less likely to enter." *Id*. at P 239 (JA 446). Fewer competitors can result in less system flexibility and reliability. *Id*. *See also Edison Mission Energy, Inc. v. FERC*, 394 F.3d at 969 (agency must ensure that market mitigation measures do not "wreak substantial harm" by "curtailing price increments attributable to genuine scarcity that could be cured only by attracting new sources of supply").

Bidders in Narrow Constrained Areas are permitted to bid their reference price plus a conduct threshold, or fixed-cost adder, before they are subject to mitigation. TEMT II Order at P 307 (JA 271). The fixed-cost adder is equal to the ratio of the net annual fixed costs of a new peaking generator per megawatt to the constrained hours. *Id*. at P 309 (JA 271). This approach reflects "the fixed costs that would need to be recovered by a hypothetical new peaking unit, the kind of unit most likely to enter a [Narrow Constrained Area] in response to price signals." Market Rules Order at P 60. Accordingly, the fixed-cost adder "provides a careful balance between the need to mitigate market power and to provide an efficient incentive to invest."[7] TEMT II Order at P 317 (JA 272).

Transmission Dependent Petitioners complain (Br. at 28-34) that the Commission unlawfully rejected their proposal to set the Narrow Constrained Area threshold at marginal cost plus 10 percent. However, the Commission reasonably explained that the Midwest ISO proposal achieved a more appropriate balance between under- and over-mitigation:

> Over-mitigation can inadvertently cause reliability problems to the extent that it keeps capacity out of the market over the longer term. Thus a range of pricing needs to be accepted that ensures suppliers can offer and mitigation does not hinder that bidding.

TEMT II Order at P 316 (JA 272). *See also* Market Rules Rehearing Order at P 46 n.35 (explaining that, during periods of constraint, existing units are operating at

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[7] *Cf. PPL Montana, LLC v. Surface Transportation Board*, 437 F.3d 1240, 1242 (D.C. Cir. 2006) (under "stand-alone" pricing in a non-competitive market, railroad freight rates can be no higher than the cost at which a hypothetical efficient carrier could provide the service).

high capacity and may incur significant marginal costs, including legitimate opportunity costs and risks). If mitigation thresholds do not accurately reflect the generation costs incurred at the time of the constraint (or the costs that a new entrant would need to recover if it built capacity in the constrained area), then they will diminish the incentive to enter the market. As the Commission emphasized, "a marginal cost estimate plus a set percentage may not reflect the costs that are incurred at the hour of the binding constraints." TEMT II Order at P 316 (JA 272).

Transmission Dependent Petitioners complain (Br. at 34) that the Commission disregarded the testimony of its expert, Dr. Kirsch, that the 10 percent threshold will not interfere with cost-reflective bidding.[8] However, the Commission did note, and respond to, Transmission Dependent Petitioners' argument that a 10 percent threshold would be appropriate for Narrow Constrained Areas. *Id.* at P 313, 316 (JA 272).

Furthermore, the supporting evidence rests on a faulty premise. Dr. Kirsch's affidavit "assumes . . . that ratemaking is an exact science and that there is only one level at which a wholesale rate can be said to be just and reasonable" – cost plus ten percent. *FPC v. Conway Corp*, 426 U.S. at 278. *See* R. 98 at Affidavit B, p. 11 (JA 1207). Dr. Kirsch also disparages the Midwest ISO's proposed Narrow

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[8] The Midwest TDUs appended four affidavits from Dr. Kirsch to their original protest. All four were dated prior to the time the Midwest ISO filed the Tariff, and therefore did not respond directly to the Tariff.

Constrained Area thresholds as "arbitrary" and "nice round numbers," and argues that the Independent Market Monitor "never explains why they are more reasonable than alternative numbers." *Id.* at 7 (JA 1203). However, as the Commission made clear, the thresholds proposed for the Midwest ISO are similar to those adopted in other regions. TEMT II Order at P 315 (JA 272). Their efficacy elsewhere supports their acceptance here, as they fall within a zone of reasonableness, which is "represented by an area rather than a pinpoint." *FPC v. Conway*, 426 U.S. at 278 (quoting *Montana-Dakota Util. Co. v. Northwestern Pub. Ser. Co.*, 341 U.S. 246, 251 (1951)).

Transmission Dependent Petitioners again cite the PJM Order to support their arguments that the 10 percent threshold is appropriate for Narrow Constrained Areas. Br. at 34. As described above, the PJM Order is irrelevant to the analysis in the earlier challenged orders. *See Jeff MacLeod v. ICC*, 54 F.3d at 892; *Altamont Gas Transmission Co. v. FERC*, 965 F.2d at 1101. Moreover, even if the PJM orders did have precedential value, they find that marginal cost plus ten percent (which is itself a "nice round number") is too low to meet the needs of generators in load pockets in PJM. *See PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 37 (2004) ("a frequently mitigated unit may set the market price in many periods when it is dispatched, and during those periods it will receive only its incremental costs + 10%, which might not be enough to enable recovery of its fixed costs over the long term.”), *order on reh’g*, PJM Order at P 27 (“[R]estricting mitigated bids to marginal (variable) cost plus ten percent . . . may undermine reliability by causing these frequently mitigated units to retire prematurely and is thus not just and reasonable” for those units), *on reh’g*, 112 FERC ¶ 61,031 (2005).

C. The Record Demonstrates How the Midwest ISO Will Calculate Narrow Constrained Area Thresholds.

Transmission Dependent Petitioners make much of the fact that the Commission did not respond to their arguments regarding the calculation of Narrow Constrained Area thresholds, but their concerns are misplaced. First, the Transmission Dependent Petitioners admitted below that they understood how the Midwest ISO will make this calculation. Second, they do not allege here (and did not argue below) that the Midwest ISO is calculating the threshold in a manner different from what the Tariff specifies. Third, Transmission Dependent Petitioners do not allege that they have suffered any harm as a result of the Commission’s decision. Their allegations and omissions make clear that any failure to address their arguments was harmless error.

Transmission Dependent Petitioners admitted in their original protest that it was their “understanding, based on the MISO stakeholder process, that the IMM intends to net any retail rate recovery against the numerator of the fixed cost adder.” (JA 1133). They stated only that the Midwest ISO’s tariff language “fails to make that clear,” making the issue one of good tariff drafting. *Id.*

The Tariff is consistent with the Midwest TDUs' understanding. Tariff section 64.1.2.c.i and Dr. Patton's testimony indicate that the Narrow Constrained Area threshold is defined as the net annual fixed costs divided by the number of constrained hours. R.25 at Tariff section 64.1.2.c.i (JA 770-72) and Exhibit Midwest ISO-11 at 52-53 (JA 832-33). "Net annual fixed costs," in turn, is defined in Tariff section 64.1.2.c.i as "annual fixed costs of a new peaking generator per [megawatt], including recovery of capital costs, *minus appropriate credits for net revenue* the new peaking generator would receive from the Market and Service provided under the Tariff and any applicable resource adequacy mechanism." *Id.* at Tariff section 64.1.2.c.i. (JA 772). Because the Tariff is sufficiently clear, it was not error for FERC to accept this provision as written.

Transmission Dependent Petitioners, moreover, do not allege that the Midwest ISO has been calculating the Narrow Constrained Area threshold incorrectly, or in violation of its tariff. Nor do they allege that they have suffered any harm from the Commission's decision to accept the tariff provision. As such, any failure to comment expressly, or with greater specificity, on the Narrow Constrained Area threshold calculation methodology is harmless error at most.

D. The Commission Reasonably Concluded That the Mitigation for Broad Constrained Areas Is Acceptable.

Transmission Dependent Petitioners incorrectly claim (Br. at 36-37) that the Commission did not respond to their arguments that generators in Broad

Constrained Areas will bid up to their conduct thresholds to avoid mitigation *See supra* page 16-17 (explaining mitigation thresholds in Broad Constrained Areas). In fact, the challenged orders state how the Commission expected bidders in Broad Constrained Areas to behave and, accordingly, why the Commission approved the Broad Constrained Area thresholds.

In a competitive market, generators will bid their marginal cost. "Efficient pricing requires that suppliers receive the highest market value for their resources, independent of their bids. This gives all sellers the proper incentive to offer their resources at the marginal cost of their highest valued use . . . ." *New York Independent System Operator Corp.*, 110 FERC ¶ 61,244 (2005). As such, the ability "to properly identify and mitigate market power relies critically on reference prices that reasonably reflect the offer that a generator would be expected to make under competitive conditions, which is its marginal cost." *ISO New England Inc.*, 111 FERC ¶ 61,184 at P 16, *reh'g denied*, 112 FERC ¶ 61,168 (2005).

Broad Constrained Areas are areas "*in which sufficient competition usually exists*, even when one or more transmission constraints are binding, or into which the transmission constraints bind infrequently," although these constraints can confer locational market power under certain conditions. TEMT II Order at P 264 (JA 265); TEMT II Rehearing Order at P 215 n.170 (emphasis added) (JA 442). "Market power concerns are thus minimal in these areas." TEMT II Order at P 264 (JA 265). The Broad Constrained Area thresholds "protect against the exercise of market power while letting generators offer their resources competitively under a range of market conditions without concerns about their bids being mitigated." TEMT II Rehearing Order at P 221 (JA 443).

The Commission's conclusion that it would be difficult for generators to successfully bid above marginal cost is reasonable. Broad Constrained Areas are not identified in advance, but dynamically as transmission constraints arise. TEMT II Order at P 246, 264 (JA 262, 265). A generator would have to know in advance when a transmission constraint would be binding in order to successfully bid above marginal cost. The Commission specifically found that generators likely would not know when a transmission constraint would be binding ahead of time. *Id.* at P 272 (JA 266).

The Commission also found that the Broad Constrained Area thresholds were appropriate to further its goal of balancing effective mitigation with competitive markets that provide appropriate economic signals. "[T]hresholds of $100 or 300 percent above reference levels are not tight," but that is because "they are in areas that are not expected to have locational market power often." TEMT II

Order at P 272 (JA 266). Additionally, the Commission (and the Independent Market Monitor) promised to monitor this issue on an ongoing basis: "[W]e do not take lightly buyer concerns that these measures will under-protect them. Thus, we will closely review market assessments to determine if the thresholds are appropriate." *Id.* (internal citation omitted). As the Court has found in the past, ongoing assessment, based on actual results, provides a substantial measure of consumer protection. *See, e.g., Electricity Consumers Resource Council v. FERC,* 407 F.3d 1232, 1238-39 (D.C. Cir. 2005) (citing cases).

E. The Commission Has Continued Broad Constrained Area Mitigation Past One Year.

Transmission Dependent Petitioners complain (Br. at 38) that the Commission erred by limiting Broad Constrained Area mitigation to a term of one year. In fact, however, the Commission merely decided to re-evaluate Broad Constrained Area mitigation after one year of energy market operations because of its concern that the Midwest ISO's market power mitigation program might lead to over-mitigation in these areas. As discussed below, that re-evaluation has been completed and the Commission has permitted the Midwest ISO to continue Broad Constrained Area market power mitigation.

In the orders challenged here, the Commission found that the Midwest ISO's proposal for defining Broad Constrained Areas gave the Independent Market Monitor discretion that could be problematic, and that it was possible that too many generators, or too few generators, might be identified as having market power. TEMT II Order at P 274-75 (JA 266-67). Accordingly, the Commission permitted the use of Broad Constrained Areas as a method to screen for the use of market power mitigation on a probationary basis. *Id.* at P 275 (JA 266-67). The Commission did "not take lightly the concerns about the potential for the exercise of market power in [Broad Constrained Area]s," but, consistent with its other findings, noted that "the difficulty is to find the appropriate balance between under-mitigation and over-mitigation." TEMT II Rehearing Order at P 230 (JA 445). It required the Independent Market Monitor to file quarterly reports in order to allow further assessment of the Broad Constrained Area approach and permitted the Midwest ISO to file to continue the use of the approach past the first year. TEMT II Order at P 275 (JA 266-67);TEMT II Rehearing Order at P 231 (JA 445).

The Midwest ISO requested an extension of Broad Constrained Area mitigation on March 10, 2006. The Commission initially rejected the request. *Midwest Independent Transmission System Operator, Inc.*, 115 FERC ¶ 61,158 at P 22-24 (2006). On rehearing, the Commission reversed its initial holding and extended Broad Constrained Area mitigation for an additional year, effective no later than August 1, 2006, and permitted the Midwest ISO to file again to extend its mitigation authority. *Midwest Independent Transmission System Operator, Inc.*, 116 FERC ¶ 61,068 at P 22-24 (2006). In light of the Commission's continued monitoring of this issue, Transmission Dependent Petitioners' complaint of Commission error lacks merit.

III. The Marginal Loss Refund Mechanism and the Ongoing Proceeding to Refine the Mechanism Are Reasonable Responses to the Marginal Loss Problem.

Transmission Dependent Petitioners contend (Br. at 40) that the Compliance Orders resulted in an "unacknowledged and unjustified about-face" on the TEMT II Order marginal loss rulings. *See supra* page 19-22 (discussing treatment of transmission losses). However, the compliance proceeding is ongoing and continues to address the loss mechanism. Consequntly, the issue has been raised prematurely and the Court lacks jurisdiction to consider it. In any event, as the Commission explained, it has not reversed its rulings.

A. Proceedings Addressing the Marginal Loss Mechanism Are Ongoing.

Judicial review of Commission orders under the FPA is limited to final orders on the merits. *See FPC v. Metropolitan Edison Co.*, 304 U.S. 375, 384 (1938) ("The provision for review . . . relates to orders of a definitive character dealing with the merits of a proceeding before the Commission . . . ."). As demonstrated below, the challenged orders are not final with regard to the loss mechanism issue. Delaying review until the underlying proceedings are completed, moreover, may avoid review entirely if the parties reach a satisfactory accommodation on the issue.

The transition from average to marginal transmission losses has been contentious in other regional markets with respect to the allocation of the surplus loss revenues. TEMT II Order at P 73 (JA 238). The issue is contentious and difficult in the Midwest ISO as well, and the Commission has required successive Midwest ISO filings in efforts to obtain a mechanism that best meets the objectives set forth in the TEMT II Order. *See*, *e.g.*, Compliance Order I at P 172 (JA 511) (requiring the Midwest ISO to make a filing explaining how it is determining marginal losses for entities with remote generation); Compliance Order IV at P 51 (JA 632-33) (requiring the Midwest ISO to provide data, with a view toward redressing any identified cross-subsidies).

Additional proceedings will follow the November 1, 2006 Order, which was issued after briefing had started and is not under review here, and which requires the Midwest ISO to analyze a loss mechanism proposed by the Transmission Dependent Petitioners:

> We will, however, require Midwest ISO to analyze the marginal loss surplus refunds calculated by the Midwest TDUs and WPS Companies in their filings and report their findings in a filing with the Commission within 90 days of this order. As well, these market participants should provide Midwest ISO with information explaining their assumptions and methods used to derive the figures quoted in the filings. To the extent Midwest ISO finds their methods acceptable for calculating the marginal loss surplus refunds, we direct Midwest ISO to determine if that method could be applied to all market participants

> and would result in a more equitable allocation of marginal loss surplus refunds than the current allocation.

November 1, 2006 Order at P 28. As the Commission has not made a final determination as to the appropriate marginal loss mechanism, judicial review is premature. *See New Mexico Attorney General v. FERC*, 466 F.3d 120, 121 (D.C. Cir. 2006) (parties lack standing to seek judicial review of conditional orders subject to a further compliance proceeding) (citing cases).

B. In Any Case, the Commission Has Not Reversed Its Findings on the Marginal Loss Mechanism.

The TEMT II Order found that:

> In the past, once marginal losses pricing has been established for all market participants, we have declined to revert to average losses. We continue to support the calculation of marginal losses as essential to achieving a least cost dispatch. However, to give market participants more time to adjust to the [locational marginal pricing] approach for setting prices and to develop confidence in market prices, we will permit surplus loss revenues to be credited to those participants whose costs from marginal losses exceed the costs that would result from average loss pricing. In other words, marginal losses will be credited back to a historical loss charge or average losses for these participants.

TEMT II Order at P 73 (JA 238).

Transmission Dependent Petitioners contend (Br. at 41) that this language means that the transitional period marginal loss surplus payments must track each market participant's "own average or historical losses." However, in response to

Transmission Dependent Petitioners' arguments below that the Commission had changed its position on how the mechanism should work, the Commission explained that their interpretation of the TEMT II Order was not correct:

> Compliance Order IV implements the requirements of the TEMT II Order in its approval of a refund mechanism that credits surplus loss revenues to participants whose marginal losses exceed costs that would result from average loss pricing. The Commission did not order that the refunds be directly assigned, as the Midwest TDUs claim. The TEMT II Order gave general guidance that the Midwest ISO should develop a single methodology for the refund of the difference between marginal and average losses. . . . [T]he Commission's approval of the pooling method was consistent with the Commission's previous directive and reflected the limitations associated with implementation; therefore, that decision was neither arbitrary nor capricious.

Compliance Order V at P 18 (internal citations omitted) (JA 638-39). This interpretation by the Commission of its own order is a reasonable one, and, as this Court has found, "if FERC interprets its own orders reasonably, then we will sustain its interpretations." *East Texas Elec. Coop., Inc. v. FERC*, 218 F.3d 750, 753 (D.C. Cir. 2000).

Finally, the arguments raised by Transmission Dependent Petitioners in their Brief at 42-50 appear directed more at the merits of the Compliance Orders' findings than at the appropriate interpretation of the TEMT II Order. In any case, the arguments underscore the prematurity of their appeal of the loss mechanism, since some are addressed in the November 1, 2006 Order. *See, e.g.* November 1, 2006 Order at P 18, 27 (addressing the Option B methodology raised here by the Transmission Dependent Petitioners (Br. at 44)).

IV. The Commission's Determination That Grandfathered Transactions Should Be Subject To Schedule 17 Charges Was Reasonable And Supported By the Record.

A. The Commission Reasonably Found That All Users of the Grid Benefit Significantly from the Midwest ISO's Energy Markets.

The Commission found that the Midwest ISO's Energy Markets will benefit all users of the transmission grid, including parties to grandfathered transactions. GFA Rehearing Order at P 174 (JA 556); GFA Order at P 298 (JA 389-90); and Schedule 16/17 Order at P 44 (JA 337). Based on that finding, FERC held that the allocation of Schedule 17 charges only to non-grandfathered users of the grid was not just and reasonable. Instead, Schedule 17 charges should be spread out among all the beneficiaries of the Midwest ISO's operations, including grandfathered load. GFA Order at P 298 (JA 389-90); GFA Rehearing Order at P 181 (JA 557).

Schedule 17 recovers the Midwest ISO's costs of providing Energy Market Service. The Commission found that the "presence of the markets produces global benefits" including "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." Schedule 16/17 Order at P 43 (JA 336-37).

The Schedule 16/17 Order explicitly rejected arguments that entities operating under grandfathered contracts would not benefit as much, or at all, from the Energy Markets. Schedule 16/17 Order at P 44 (JA 337). These entities, like all market participants, benefit through the increased reliability of the grid:

> For example, such transactions will likely be subject to fewer Transmission Loading Relief (TLR) calls with the establishment of energy markets . . . . [P]reventing 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.

Id. (footnotes omitted).

Fewer TLRs also result in a more efficient transmission grid. *Id*. at P 45-46 (JA 337). TLRs are inefficient because they may curtail more transmission than necessary to relieve a constraint:

> 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 effect on the parties.

Schedule 16/17 Order at P 45 (JA 337) (citing a study by the Midwest ISO's Independent Market Monitor). The study showed that "the TLR process, on average, curtails more than three times the quantity of transactions as could be redispatched to achieve the same result . . ." *Id*. at P 46 (JA 337).

The Commission also concluded that the Energy Markets 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." *Id*. at P 47 (JA 337).

The concurrently-issued GFA Order affirmed these findings and concluded that grandfathered agreements receive the same reliability and efficiency benefits as other entities using the transmission grid. GFA Order at P 297-98 (JA 389-90). Consequently, they should be assessed the Schedule 17 charges regardless of whether they are carved out of the Energy Markets. *Id*. at P 298 (JA 389-90).

The GFA Order explained further the disadvantages of continued reliance on congestion management though TLRs. When not all scheduled service can be physically accommodated, transmission service is physically curtailed through use of TLRs, based upon priorities related to firmness and length of service, resulting in under-utilization of assets. *Id.* at P 27 (JA 347) (summarizing submission by Dr. McNamara). "Reliance on TLRs for congestion management inherently leaves transmission capacity under-utilized because the TLR approach relies on imprecise flow estimates and cannot accurately reflect system interactions." GFA Order at P 30 (JA 347).

The GFA Order also examined analyses by the Midwest ISO and by the Independent Market Monitor of TLR events in 2003. GFA Order at P 32-34 (JA 348). Both studies demonstrated that reliance on TLRs makes it more difficult to maintain power flows within operating security limits.

FERC later reiterated that the Energy Markets provide global benefits to all entities transacting over the Midwest ISO grid. GFA Rehearing Order at P 176 (JA 556). With centralized security-constrained dispatch, the Midwest ISO centrally dispatches generation as needed to account for security constraints. *Id*. at P 177 (JA 556-57). This system "allows the Midwest ISO to respond to and relieve security violations more quickly and precisely than the TLR process and results in more efficient utilization of the transmission system, increasing the supply of competing generation available to serve load and contributing to more reliable service to all those who transact over the Midwest ISO system." *Id*.

The Commission also relied upon the Final Report on the August 14, 2003 Blackout.[9] GFA Rehearing Order at P 177 (JA 556-57). The Report found that the TLR procedure is not fast and predictable enough for use in situations in which an

[9] On August 14, 2003, large portions of the Midwest and Northeast United States and the province of Ontario, Canada experienced an electric power blackout that affected an estimated 50 million people. Power was not fully restored in some parts of the United States for four days and parts of Ontario suffered rolling blackouts for more than a full week. The Blackout Report, which was prepared by a joint U.S.-Canada Power System Outage Task Force, may be found at http://www.nrcan.gc.ca/media/docs/final/B-F-Web-Part1.pdf.

Operating Security Limit is close to or actually being violated, and should not be used in situations involving actual violation of an Operating Security Limit. Accordingly, the "Midwest ISO's Energy Markets represent a significant improvement over current reliability practices and will produce reliability benefits to all using the Midwest ISO's transmission system." *Id*.

The Commission also reiterated that the Midwest ISO's markets provide price signals that will facilitate identification of cost-effective transmission system improvements to reduce congestion. *Id.* at P 178 (JA 557). Price signals will also facilitate demand response in the electric energy markets, which will reduce the potential for curtailments, system emergencies or price spikes, due to shortages. *Id*. In addition, grandfathered agreement parties can benefit by participating in the spot markets, when it is economic to do so. *Id*. at P 179 (JA 557).

B. The Commission Followed Appropriate Cost Causation Principles.

Cooperative Petitioners, which are parties to certain grandfathered agreements, contend (Br. at 36-37) that the Commission failed to meet basic "cost causation" principles which, they claim, require efforts to match precise costs and benefits for particular classes of customers. They claim that grandfathered agreements do not use Energy Markets services and should not be charged for services that they do not use (Br. at 40-45).

Contrary to the Cooperative Petitioners' claim, however, the Commission did meet applicable cost causation principles. The Commission's decision to allocate some of the Schedule 17 Energy Markets costs to grandfathered load is premised on the global benefits that grandfathered load receives from operation of the markets. Cooperative Petitioners ignored precisely the same cost causation principles they now cite by proposing that none of the Schedule 17 costs be allocated to grandfathered load, even though that load benefits from the improved grid reliability and efficiency that the Energy Markets provide.

The Commission reasonably acted to ensure that all – instead of only some – users of the grid that benefit from the Midwest ISO's market operations pay a share of the operating costs. The decision to allocate costs among all users that benefit from their incurrence is entirely consistent with ratemaking precedent. It is established Commission policy that all customers using an integrated transmission grid share in the costs of the grid, because they all benefit. That ratemaking policy has been affirmed by the courts. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1371 (costs may be imposed when benefits, such as overall reduction in costs of transmitting energy and large scale regional planning and coordination, redound to all users of the transmission grid); *Entergy Services, Inc. v. FERC*, 319 F.3d 536, 542-45 (D.C. Cir. 2003) (affirming the Commission's roll-in to all transmission customers of the costs of interconnecting the grid to additional generation, based on the agency's judgment that all users of the grid benefit from short-circuit and stability upgrades enhancing grid reliability); *Western Massachusetts Electric Co. v. FERC*, 165 F.3d 922, 927-28 (D.C. Cir. 1999) (affirming Commission's decision to roll-in costs to all transmission customers, based on presumption that "[w]hen a system is integrated, any system enhancements . . . . benefit the entire system") (citing cases).

Cooperative Petitioners' argument (Br. at 40) that they should not "be charged for services they do not utilize" thus lacks merit. Even if they are not in some sense using the Energy Markets, the GFA parties still benefit from having them, for all of the reasons discussed above. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1371 (comparing benefits of having an ISO to benefits of having a court system, which flow to litigants (users) and non-litigants (non-users) alike). Moreover, even parties that normally transact under grandfathered agreements can benefit from the Energy Markets by participating in the spot markets when it is economic to do so, "either directly, or through bilateral transactions with price formation aided by transparent market prices produced by the [Energy Markets]." GFA Rehearing Order at P 179 (JA 557). In sum, parties transacting under grandfathered agreements draw benefits from the Energy Markets and, accordingly, should share the cost of receiving them.

C. The Commission Was Not Required to Perform a "Net Benefit" Analysis.

For similar reasons, Cooperative Parties also err in arguing (Br. at 34-35, 37) that cost causation principles required Commission analyses of "net benefits" to grandfathered agreements. A primary purpose of the statutes governing Commission authority is to assure adequate service at reasonable rates. *Public Utilities Comm'n of California v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) (quoting *NAACP v. FPC*, 425 U.S. 662, 669-70 (1976)) ("the principal purpose of those Acts was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices"). To carry out this purpose, the Commission may consider non-cost factors as well as cost factors in setting rates. *Permian Basin Area Rate Cases*, 390 U.S. 747, 791, 815 (1968); *Public Utilities Comm'n of California*, 367 F.3d at 929 (affirming 200 basis point incentive adder to encourage facilities construction). The assessment of how to balance cost and non-cost factors must be justified by a showing that "the goals and purposes of the statute will be accomplished through the proposed changes," *Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18, 31 (D.C. Cir. 2002) (citation omitted), and does not require mathematical precision. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1371 ("the cost causation principle does not require exacting precision in a ratemaking agency's allocation decisions").

Here, the challenged orders demonstrate that all users of the transmission grid will benefit from improved reliability and efficiency. These benefits have both cost and non-cost implications, and some of the benefits, defying precise quantification, will accrue primarily in the future as a result of more cost-effective transmission system improvements and generation siting. The Commission has explained how the Midwest ISO proposal it approved will carry out "the goals and purposes of the statute," *see Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d at 31, and, under the circumstances, that is sufficient. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1371 ("the cost causation principle does not require exacting precision in a ratemaking agency's allocation decisions").

D. The Cooperative Petitioners' Other Arguments Are Unavailing.

The Cooperative Petitioners' other arguments are primarily variations on the theme that the benefits to the grandfathered parties are unsupported. As demonstrated above, the Commission's determination that grandfathered parties would benefit from the new markets was well founded.

In any event, the Cooperative Petitioners' contention (Br. at 27-29) that the Procedural Order required the Midwest ISO "to demonstrate benefits of the [Tariff] to GFA transactions" misses the point. The point was to obtain information on the impact that including or carving out grandfathered agreements would have on the reliability and economic benefits of the proposed congestion management system. *See* Procedural Order at P 72-73 (JA 13). Thus, the focus was not, as Cooperative Petitioners suggest, on quantifying specific benefits to the grandfathered agreements, but the effect of the grandfathered agreements on the benefits to be achieved generally through the TEMT.

Cooperative Petitioners' argument (Br. at 29-31) that the Midwest ISO failed to respond adequately to the Procedural Order is also off the mark. Contrary to Cooperative Petitioners' contention (Br. at 30-31) that the evidence addressed only economic efficiency, the Midwest ISO and the Independent Market Monitor submitted evidence demonstrating that the proposed congestion management method would increase grid reliability. *See* discussion *supra* at 58-62. In any case, the Commission's findings were based on the record as a whole. *See* GFA Rehearing Order at P 174-75 (JA 556).

The Cooperative Petitioners argue (Br. at 34) that the Commission resorted to the "design" of the Energy Markets and that this was a "hollow" rationale given that the markets' design had not changed. However, the "Commission's ultimate findings on the allocation of Schedule 17 costs in the GFA Order were based on the *record* concerning the design of Midwest ISO's TEMT . . .," GFA Rehearing Order at P 175 (JA 556) (emphasis added), and that record had been supplemented. Moreover, even if nothing had changed, Cooperative Petitioners' argument ignores the fact that the Commission is not required to reach the same conclusion in every decision in a proceeding. *See Ameren Services Co. v. FERC*, 330 F.3d 494, 499 n.8 (D.C. Cir. 2003) ("The very purpose of rehearing is to give the Commission the opportunity to review its decision before facing judicial scrutiny.").

Cooperative Petitioners' complaint (Br. at 35) about the "potential dangers" of "theoretical market design" and comparison to the 2000-2001 California energy crisis ignore the fact that Midwest ISO's Energy Markets "incorporate the major features used successfully in the three eastern ISOs – PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO), and ISO New England (ISO-NE) – including centralized security-constrained economic dispatch, [locational marginal pricing] and market mitigation based on conduct and impact thresholds." TEMT II Order at P 2 (JA 228). Cooperative Petitioners' comparison (Br. at 35) of the Midwest ISO's proposal to the "meltdown of California's energy markets" thus lacks merit.

The argument (Br. at 41-44) that the submission of voluntary schedules to the Midwest ISO by transmission owners for grandfathered agreement transactions is for the benefit of the ISO and does not constitute use of Energy Market services by grandfathered agreement parties fares no better. The Commission's conclusion that grandfathered agreement parties should pay Schedule 17 costs was not based upon direct use by those parties of Energy Market services. Rather, it relied upon the benefits that the Markets bring to all those (including the GFA parties) who use the transmission grid. GFA Order at P 298 (JA 389-90).

E. The Commission's Procedures Were Fair and Accorded the Parties Due Process in All Respects.

Cooperative Petitioners assert (Br. at 45) that the Commission denied them due process and violated the Administrative Procedure Act by failing to set the Schedule 17 issues for hearing. As demonstrated below, however, the Commission had an ample record on which to base its findings. Cooperative Petitioners presumably object to the absence of a formal evidentiary, trial-type hearing before an administrative law judge on their particular claims. The formulation of procedures is a matter of agency discretion. *Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council*, 453 U.S. 519 (1978). *See Michigan Public Power Agency v. FERC*, 963 F.2d 1574, 1579 (D.C. Cir. 1992) (agencies accorded substantial deference in ordering their proceedings). The Commission's Rules of Practice and Procedure, *see* 18 C.F.R. part 385, do not require evidentiary hearings. Moreover, the Commission need not hold an evidentiary hearing unless material issues of fact are in dispute, *Conoco, Inc. v. FERC*, 90 F.3d 536, 543 n.15 (D.C. Cir. 1996), and, even then, the Commission "is required to hold hearings only when the disputed issues may not be resolved through an examination of written submissions," *id.* at 544. *See also, e.g., Arkansas Electric Energy Consumers v. FERC*, 290 F.3d 362, 369-70 (D.C. Cir. 2002) (agency's discretion to rely "on the written record" and "to forego an evidentiary hearing" subject to review only for "abuse of discretion").

Here, the Commission's procedures were appropriate. Cooperative Petitioners argue that the Midwest ISO did not file workpapers supporting the economic benefits of the congestion management system and that they were not able to challenge the Midwest ISO's claims through discovery and cross-examination. However, the Commission's findings of benefit to the grandfathered agreements were based on the "broader range of economic and reliability benefits that the Midwest ISO's market is designed to achieve," not solely on the "subset of near-term benefits" quantified in the Midwest ISO's analysis. GFA Rehearing Order at P 175 (JA 556). Consequently, additional proceedings were unnecessary. *Id*.

V. The Treatment Accorded the Grandfathered Agreements Was Reasonable.

A. The Grandfathered Agreements Presented a Significant Obstacle to Implementation of the Midwest ISO's Proposals.

Grandfathered agreements executed prior to the formation of the Midwest ISO in 1998, *see supra* page 10, presented a significant problem to the development of the enhanced "Day 2" markets, because the agreements generally contain terms of service that are incompatible with centralized dispatch and locational marginal pricing congestion management. *See* Procedural Order at P

15-17 (JA 3-4). The Midwest ISO initially estimated that up to 40 percent of its total load was provided under such agreements. *Id.* at P 16; GFA Order at P 4 (JA 3-4, 343). The Midwest ISO stated that permitting grandfathered agreement parties to schedule transmission in real time, as they were accustomed to doing, would require a physical reservation, or carve-out, of transmission capacity in the day-ahead energy market. Procedural Order at P 15, 61 (JA 3, 11). This could increase congestion costs and place an excessive financial burden on other market participants, or could threaten transmission system reliability. *Id*. at P 15, 55 (JA 3, 10). The problem was a threshold issue in the Commission's consideration of the Tariff. Procedural Order at P 3 ("The Midwest ISO's proposed method of congestion management is a high priority for the Commission, due to its reliability benefits and its economic efficiency benefits, but we firmly believe that it should not start until the GFA issue is more completely addressed.") (JA 1).

While ultimately the percentage of total load under grandfathered agreements was less than 40 percent, the issue of their treatment in the Energy Markets remained and required FERC to balance conflicting objectives in their resolution. GFA Order, P 5 ("[W]e find that, even with this carve-out, the Midwest ISO's Energy and FTR Markets will be more reliable and efficient overall than the market currently in place in the region.") (JA 343). These objectives were the encouragement of energy market development, preservation of the bargain the transmission owners relied upon in creating the Midwest ISO, allocating costs appropriately, and respecting the contractual relationships between the parties.

(1) Encouragement of a Market-Based Congestion Management System in the Midwest ISO

As detailed *supra* pages 58-62, the Commission has expected that all users of the transmission grid – even parties under grandfathered agreements, which do not transact in the Energy Markets – would benefit from the significant reliability and efficiency improvements resulting from market-based congestion management. Consequently, initiation of Day 2 Energy Markets in the Midwest ISO was an important objective.

(2) Maintaining the Bargain the Transmission Owners Struck When They Voluntarily Formed the Midwest ISO

The transmission owners were not required to form an ISO. *See* Order No. 888 at 31,730-32; *see also Public Utility District No. 1 of Snohomish County v. FERC*, 272 F.3d 607, 609 (D.C. Cir. 2001). Moreover, there was no pre-existing power pool in the Midwest, so ISO formation was a more daunting task there than elsewhere. *See* ISO Formation Order at 61,142. Nevertheless, with Commission encouragement, the Midwest transmission owners formed an ISO that provided definite benefits to grid users: enhanced reliability and security, an overall reduction in the costs of energy transmission, and regional coordination and transmission planning. *Midwest ISO Transmission Owners v. FERC*, 373 F.3d at

1369-71. Fundamental to the formation proceedings was the Commission-approved agreement that grandfathered agreements would not be placed under the ISO tariff until after a six-year transition period. *Id.* at 62,138. In view of this history, the Commission considered preservation of the ISO formation bargain a significant objective. GFA Rehearing Order at P 82 (JA 541).

(3) Allocating Costs Appropriately

Because they predate the energy markets and the formation of the Midwest ISO, grandfathered agreements are written to function in a utility structure and regulatory environment entirely different from what now prevails in the Midwest:

> In the bad old days, utilities were vertically integrated monopolies; electricity generation, transmission, and distribution for a particular geographic area were generally provided by and under the control of a single regulated utility. Sales of these services were "bundled," meaning consumers paid a single price for generation, transmission, and distribution. As the Supreme Court observed, with blithe understatement, "competition among utilities was not prevalent."

Midwest ISO Transmission Owners v. FERC, 373 F.3d at 1361. The bundled rate under which electric energy was sold in the "bad old days" included charges that can now be separately identified and billed, such as congestion costs.

The Midwest ISO's filing indicated that most grandfathered agreements did not explicitly allocate congestion costs to contract parties, and that none of the grandfathered agreements required payment of marginal losses (although many GFA parties pay average losses). Procedural Order at P 60 (JA 11). Therefore, if the parties to grandfathered agreements were required to pay the congestion costs associated with transactions under their agreements, they would effectively be double-billed for these costs. Conversely, if congestion costs associated with the grandfathered agreements were "uplifted," or socialized across non-grandfathered transactions, then the parties to those transactions would be bearing costs that they did not cause. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1368 (describing cost causation principle as "requiring that all approved rates reflect to some degree the costs actually caused by the customer who must pay them"). Intensifying the problem, there was evidence that permitting grandfathered agreement parties to schedule transmission in real time, as they were accustomed to doing, would increase congestion costs and locational marginal prices:

> Scheduling for GFAs under a physical carve-out would not be tied to energy market scheduling requirements; therefore, parties to these contracts may schedule on short notice . . . . The Midwest ISO must therefore assume that all capacity represented in GFAs will be used and, in the day-ahead market, reserve that capacity for GFA transactions even if it is unlikely that all the capacity will be utilized. As a result, transmission paths may become artificially congested more quickly than they would if all transactions were scheduled at the same time. The result – phantom congestion – would be reflected in [locational marginal] prices; consequentially, those prices may become artificially elevated.

Procedural Order at P 61 (JA 11). Permitting the grandfathered agreements to have scheduling priority over all other energy market transactions, consistent with the terms of the agreements, therefore raised the specter of undue discrimination. *Id.* at P 62 (JA 11).

(4) Respecting Contractual Relationships

The Midwest ISO initially proposed abrogating the grandfathered agreements to the extent necessary to permit them to follow Midwest ISO scheduling protocols, which would minimize the reliability and cross-subsidization concerns associated with a carve-out of transmission capacity. Procedural Order at P 18-22 (JA 4-5). However, contracts with a *Mobile-Sierra* clause cannot be abrogated unless the "public interest" so requires, and a plurality of the grandfathered agreements included such a clause. *See* GFA Order at P 141 (JA 365). Consequently, the Commission "regard[ed] any potential modification of the GFAs with great seriousness," Procedural Order at P 49 (JA 9), and consistently encouraged a resolution of the grandfathered agreements problem that would preserve existing customers' rights while ensuring a fair allocation of congestion and other costs associated with the new energy markets. Procedural Order at P 46 (JA 9); TEMT I Order at P 60.

B. The Commission's Balancing of the Conflicting Considerations Was Reasonable.

In light of the threshold nature of the grandfathered agreement problem, the quantity of data needed to analyze it, Procedural Order at P 68 (JA 12-13), and the number of factors that the Commission needed to balance in order to resolve it, the

Commission established a three-step investigation into the nature of the agreements under FPA § 206. (The investigation is described in detail *supra*, pages 25-26.) The Commission entered the process with an open mind as to the results, stating that it intended the investigation to "provide the basis for us to decide whether GFA operations can be coordinated with energy market operations, whether and to what extent the [transmission owners] should bear the costs of taking service to fulfill the existing contracts and whether and to what extent the GFAs should be modified."[10] Procedural Order at P 67 (JA 12).

The exhaustive procedural requirements that the Commission imposed to discover further information about the grandfathered agreements, *see supra* page 25, resulted in a large number of settlements – that is, decisions by grandfathered parties to convert their contracts to Tariff service or to transact under one of the Midwest ISO's proposed options for scheduling and settling grandfathered transactions. GFA Order at P 274-75 (JA 386). Under Option B (the option contested here), the grandfathered agreement parties can avoid Tariff congestion costs but, in exchange, agree to submit their schedules a day ahead. *Id*. at P 227 (JA 379).

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[10] The Commission explicitly did not preapprove the Tariff filing at the time it initiated the investigation. Resolution of the threshold grandfathered agreement issue was required for the Commission to determine whether the Tariff was just and reasonable in accordance with FPA § 205. Procedural Order at P 3 (JA 1).

With regard to grandfathered agreements that did not settle, the Commission found that some of the agreements could be modified under the FPA § 205 "just and reasonable" standard, and should be so modified to allow participation in the Energy Markets. *Id.* at P 136-40 (JA 364-40). This left a relatively small number of grandfathered agreements either subject to the more stringent *Mobile-Sierra* "public interest" standard, silent as to the standard, or with a non-jurisdictional transmission provider. *Id.* at P 129-50 (JA 363-67). The Commission found that the Midwest ISO could reliably operate its energy markets with a carve-out of this small number of grandfathered agreements. *Id.* at P 142-44 (JA 365). While integrating these agreements into the markets would have resulted in additional market efficiencies, these benefits would have come at the expense of other objectives, including preserving the bargain made during formation of the ISO.

C. The Commission Properly Respected the ISO Formation Bargain and the Contract Rights of Parties to Grandfathered Agreements.

Transmission Owning Petitioners contend (Br. at 11-13) that it is the service that the Midwest ISO provides to the transmission owners (not the service that the transmission owners provide to their grandfathered customers) that is relevant to resolution of grandfathered agreement issues, and that the *Mobile-Sierra* implications, *see supra* page 6, of the grandfathered agreements need not be considered. However, these two aspects of service to grandfathered customers cannot be so neatly separated. The transmission owners take service under the

Midwest ISO Tariff for their grandfathered transactions only as a result of their voluntary formation of the ISO (and the ensuing RTO), from which all grid users benefit.

As discussed earlier, formation of the ISO and RTO fundamentally changed the regulatory environment and the way utilities operate. *See*, *e.g.*, GFA Rehearing Order at P 87 (JA 542). Among other things, the RTO must be the only provider of transmission service over the facilities it controls. This optimizes the reliability, efficiency, and infrastructure benefits that RTOs provide. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1364 (quoting Order No. 2000).

To satisfy the Order No. 2000 "sole provider" requirement, the Commission required the transmission owners to take service under the Midwest ISO Tariff to meet their GFA obligations. GFA Rehearing Order at P 81 (JA 541). However, the Commission did not subject the transmission service fully to the tariff rates. "Rather, in order to balance Order No. 2000's requirements against its desire to preserve the bargain that many of the transmission owners relied upon in creating the Midwest ISO, the Commission [] put the GFA Service under the Midwest ISO Tariff only to the extent necessary to meet Order No. 2000's requirement that the Midwest ISO be the sole provider of transmission service." *Id.*

In determining the appropriate treatment of the grandfathered agreements in Day 2 markets, the Commission again balanced preservation of the ISO formation bargain against other priorities. *Id*. at 82 (JA 542). As the Commission explained, the *Mobile-Sierra* implications of the grandfathered agreements affected this balancing. *See id*. at P 87-100 (JA 542-44). For "just and reasonable" grandfathered agreements, the Commission concluded that the parties could modify the agreements to account for cost shifts resulting from RTO formation. *Id*. at P 88. (JA 542). Consequently, in balancing preservation of the ISO bargain with the goal of improving market reliability and efficiency, the Commission found that it would be "unjust and unreasonable" to allow grandfathered agreements that are subject to a just and reasonable standard to remain outside the Energy Markets. *Id.*; GFA Order at P 137 (JA 364).

For "public interest" grandfathered agreements, the balancing came out differently. Many transmission owners contended that subjecting these agreements to the Energy Markets during the transition period would be contrary to the ISO formation bargain. GFA Rehearing Order at P 94 (JA 543). After weighing the competing considerations, the Commission agreed and determined that these agreements should be carved out:

> We believe that we struck a reasonable balance between ensuring that the GFAs do not threaten the reliability and efficiency of the Midwest ISO's Energy Markets while ensuring that the initiation of the Energy Markets does not unnecessarily result in trapped costs for the transmission owners inconsistent with the transition period arrangement we accepted in the original Midwest ISO Agreement. While [Duke Energy] is correct that

> additional market efficiencies could have been achieved by subjecting all GFAs to [the Day 2 energy markets], those benefits would have come at the expense of other important objectives, as we have discussed here. What we have done reflects our balancing of these competing concerns.

GFA Rehearing Order at P 95 (JA 543); *see also id*. at P 96-97 (JA 543-44).[11]

Transmission Owning Petitioners nevertheless contend (Br. at 13) that FERC misapplied *Mobile-Sierra* because the doctrine allegedly does not shield contract parties when "outside circumstances" cause contract terms to become unfavorable to one of them. However, RTO formation is not an "outside circumstance" imposed upon contract parties which, under *Mobile-Sierra*, they must accept. Rather, the transmission owners voluntarily formed an ISO (which benefited all grid users) and, in the challenged orders, the Commission respected the bargain that the formation agreement contemplated.

Transmission Owning Petitioners' narrow focus on the service that the Midwest ISO provides to the transmission owners loses sight of the fact that RTO formation (and development of Day 2 markets) both fundamentally change the way utilities operate and provide reliability and efficiency benefits to users of the transmission grid. The accommodation of grandfathered agreements in this

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[11] As discussed *infra* at 81-82, this balancing also fully considered cost shifting that might occur as a result of the carve-out of grandfathered agreements.

regulatory environment required resolution of difficult issues. As the challenged orders demonstrate, the Commission's consideration of *Mobile-Sierra* was necessary, and its balance of the competing considerations reasonable. *See Atlantic City Electric Co. v. FERC*, 295 F.3d at 13-15 (invalidating Commission orders which, unlike the instant orders, reformed pre-ISO/RTO agreements with "public interest" *Mobile-Sierra* language, in light of ISO and regional developments, and without individual scrutiny).

D. The Commission's Treatment of the Grandfathered Agreements Was Reasonable.

Transmission Owning Petitioners contend (Br. at 17, 19-23) that they will be unduly harmed by cost shifts resulting from the transitional treatment of grandfathered agreements, and make various objections to the Commission's balancing of the conflicting considerations. These arguments lack merit.

Contrary to Petitioners' argument (Br. at 17), that "the Commission failed to consider the level of costs shifted," the Commission addressed the issue fully. The Commission recognized that a carve-out could potentially increase congestion charges for non-grandfathered transactions by reducing the allocation of FTRs to non-grandfathered parties, GFA Order at P 89, 99 (JA 356-57, 358), and that "a larger proportion of carved-out and Option B GFAs in a particular geographic area might in theory result in a disproportionate impact on non-GFA transactions in the area compared to the region as a whole." GFA Rehearing Order at P 99 (JA 544); *see supra* page 76 (describing Option B).

The Commission concluded, however, that such concerns were speculative. *Id*. at P 99 (JA 544). The requirement that transactions under these grandfathered agreements be scheduled in good faith on a day-ahead basis would help ensure efficient prices in the markets. *Id*. Moreover, the Commission "instituted reporting requirements to allow it to monitor scheduling behavior under carved-out and Option B GFAs to determine the impacts on market efficiency." *Id*. The Commission also required the Midwest ISO to "report any instances of pro rata FTR reductions that were significantly impacted by carved-out GFAs," and, "in its quarterly informational filings on the accuracy of carve-out schedules, any instances where it finds inefficient market prices resulting from inaccurate schedules associated with carved-out and Option B GFAs." *Id*.

Contrary to Transmission Owning Petitioners' assertions (Br. at 21), moreover, the Commission did not "admit" that "Option B and the carve-out would create significant problems." When addressing the impact in particular areas, the Commission found them "speculative," as indicated above. More generally, the Commission "expect[ed] [the economic impacts of a carve-out] to be minor, in light of the small percentage to be carved-out." GFA Order at P 99 (JA 358).

The Commission reached a similar conclusion with regard to Option B:

> We also acknowledge that the use of Option B does cause uplift for all non-Option B parties. However, the extent of that uplift is mitigated by the limited number of [megawatts] and limited number of parties that chose Option B . . . .

Id. at P 267 (JA 385). Likewise, while acknowledging the theoretical chance of anticompetitive gaming under Option B, the Commission found that:

> [T]he possible financial impacts of such activities are outweighed by the benefits to the operations of the Day 2 market by incorporating the day-ahead scheduling under the Option B method. In this regard, we reiterate that the amount of energy associated with the GFAs that settled on Option B is currently less than 5 percent of the overall market and the amount of uplift associated with these contracts would be correspondingly small.

Id. at P 269 (JA 385).

Transmission Owning Petitioners cite testimony (Br. at 21) for the proposition that carve-outs will have dire effects. As Petitioners agree, however, (Br. at 22 n.7) this testimony was directed at the Midwest ISO's estimate that up to 40,000 megawatts of transmission service capacity (approximately 40 percent of the Midwest ISO load) was provided under grandfathered agreements. *See* GFA Order at P 24 (discussing Dr. McNamara's testimony), P 36 (addressing Dr. Hogan's testimony); P 98 n.58 (addressing Dr. Tabor's testimony) (JA 347, 348, 358). The carved-out and Option B grandfathered agreements, of course, actually constitute a much smaller portion of the market. *See* GFA Order at P 98 n.58 (in response to comments concerned about a market with a very high proportion of grandfathered agreements, stating that "that circumstance will not exist [in the Midwest ISO markets] where only a small percentage of loads will remain under carved-out GFAs") (JA 358). Transmission Owning Petitioners contend (Br. at 23) that because testimony indicated a carve-out of 40 percent of the Midwest ISO's total capacity would severely impact the ISO markets, they will suffer significant harm because they have a "relatively high" concentration of Option B and carved-out grandfathered agreements. However, as the Commission found, this leap is speculative.

The Commission's treatment of potential cost shifts, moreover, represented an appropriate balance of the competing concerns. Although the Commission found Transmission Owning Petitioners' contentions of "significant harm" to be speculative, out of an abundance of caution the Commission required the Midwest ISO to report regularly on the impact (if any) the grandfathered agreements have on the market so that if "significant harm" appeared, it could be remedied. As the Court has found in the past, ongoing assessment provides a substantial measure of consumer protection. *See Environmental Action v. FERC*, 996 F.2d at 406, 410-12.

The Commission also considered the reliability and other benefits of the Day 2 markets. The Transmission Owning Petitioners' complaint about transitional cost shifts ignores these benefits that the new markets provide them. The

Commission concluded that the new markets will provide net benefits to the public regardless of the fact that some grandfathered agreements have not been integrated. GFA Rehearing Order at P 93, 97 (JA 543-44); *see also id*. at P 97 (Commission "considered the increased scope of the redispatch capability that will be available in the Midwest ISO's centralized dispatch, the measures that the Midwest ISO will take on a day-ahead and real-time basis to anticipate and respond to security constraints and reliability requirements, and the incentives that [locational marginal pricing] markets provide market participants to manage their sales, purchases, and transmission use more efficiently in a way that supports reliability.") (JA 543).

Transmission Owning Petitioners argue (Br. at 18, 24) that the Commission failed to consider the additional efficiency and reliability benefits that could be obtained by avoiding the carve-out. However, the challenged orders demonstrate that the Commission considered this factor:

> Finally, [Duke Energy] is correct that additional market efficiencies could have been achieved by subjecting all GFAs to Options A or C. However, as discussed above, there were and are competing concerns that the Commission must weigh against such additional efficiencies.

Id. at P 100 (JA 544). Among the competing concerns was, *inter alia*, "ensuring that the initiation of the Energy Markets does not unnecessarily result in trapped costs for the transmission owners inconsistent with the transition period arrangement that [the Commission] accepted in the original Midwest ISO Agreement." GFA Rehearing Order at P 95 (JA 543).

E. Transmission Owning Petitioners' Other Arguments Are Unavailing.

(1) The Commission's Rulings Do Not Contradict Cost Causation Principles.

Transmission Owning Petitioners assert (Br. at 13-14, 26-28) that the Commission's rulings contradict cost causation principles generally and, more specifically, the Commission's application of *Mobile-Sierra* to non-settling, jurisdictional grandfathered agreements. In evaluating compliance with the cost causation principle, courts "compar[e] the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1368. However, a ratemaking agency is not required "to allocate costs with exacting precision;" it is enough that "the cost allocation mechanism not be 'arbitrary or capricious' in light of the burdens imposed or benefits received." *Id*. (citations omitted).

The Commission satisfied this principle. As explained *supra* at 63, Schedule 17 charges are analogous to Schedule 10 administrative charges and are charged to GFA parties because of the general benefits they receive from system improvements. *See id.* at 1371; GFA Rehearing Order at P 180 (JA 557). The charges that Transmission Owning Petitioners would impose on non-settling, jurisdictional grandfathered agreements, in contrast, are transactional costs that the grandfathered parties effectively already pay for through the grandfathered agreements. Procedural Order at P 60 (JA 11). *See also Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1366 (describing transactional charges in the Midwest ISO open access tariff).

(2) The Commission Properly Applied the *Mobile-Sierra* "Public Interest" Standard.

Transmission Owning Petitioners contend (Br. at 17) that even "assuming *arguendo* that subjecting the non-settling, public interest GFAs to Options A or C or [Tariff] service would modify the GFAs, and thus would have to satisfy the public interest standard of review, the detrimental third-party effects of the carve-out amply meet that standard." This argument overlooks the fact that "the public interest standard of the *Mobile-Sierra* doctrine is much more restrictive than the just and reasonable standard." *Atlantic City Electric Co. v. FERC*, 295 F.3d at 14. Contract reformation must be based upon "a particularized finding that the public interest required the modification of the [contract in question]." *Id*.

In *Atlantic City*, the Commission had made a "generic" finding that existing bilateral and power sale agreements of ISO members in a neighboring region had to be modified because the restructuring plan transferred the obligation to provide open access transmission services from the individual utility owners to the ISO. The Court found that this did not satisfy the *Mobile-Sierra* public interest standard.

Id. at 14-15 (admonishing the Commission "to heed its own admonition and 'not take contract modification lightly'").

Transmission Owning Petitioners argue (Br. at 17-18) that the Commission failed to consider in addition whether the cost shifts created by the carve-out and the additional reliability and efficiency benefits that would accrue by avoiding the carve-out justify a public interest contract modification. However, the Commission did, in fact, consider these factors:

> In sum, having found that the Midwest ISO could operate the Energy Markets reliably and with net benefits to the public with the integration into the Energy Markets of just the settling GFAs and the just and reasonable standard of review GFAs, the Commission did not need to pursue the conversion of the GFAs in the *Mobile-Sierra* public interest, silent, and non-jurisdictional categories.

GFA Rehearing Order at P 93 (JA 543). Even with the potential cost shifts and lesser market efficiencies, market participants – including Transmission Owning Petitioners – still benefit from the Day 2 markets. Abrogating contracts so that certain members of the public may receive additional benefits is far removed from protecting the public against events such as utility bankruptcy, cited by the *Mobile-Sierra* decisions as an example of the "public interest." Finally, cases such as *Atlantic City* require a "particularized finding" that contracts required modification. There were about 77 agreements in this category; presumably each would have had to be examined to determine its particular impact on the Energy Markets with concomitant delay in obtaining the benefits of the Energy Markets.

(3) The Commission's Treatment of "Just and Reasonable" and "Public Interest" Grandfathered Agreements Was Consistent.

Transmission Owning Petitioners contend (Br. at 14-15) that since an objective of the Commission was to preserve the agreement the transmission owners made in forming the ISO, the Commission acted inconsistently when it carved out "public interest" grandfathered agreements but not "just and reasonable" ones. This ignores the fact that the Commission balanced competing considerations in determining the appropriate treatment of the grandfathered agreements. For those in the "just and reasonable" category, the Commission recognized that:

> [T]he Commission and the parties are able to modify these contracts based on the just and reasonable standard of review. By explicitly reserving their rights to seek modifications to their contracts, these parties specifically negotiated and contemplated that their contracts could be modified during the term of the contract based on the just and reasonable standard of review. To the extent that costs are shifted between parties to GFAs in this category, the terms and conditions of the GFAs would allow the parties to propose appropriate modifications to reflect such new costs. Since these contracts specifically contemplated modifications to reflect a realignment in costs and benefits among the parties to the GFAs, the Commission found that: "in order to balance the [transmission owners'] concerns that the Midwest ISO's proposed treatment of GFAs will lead to trapped costs

> with the Midwest ISO's concern that leaving GFAs intact will negatively impact reliability, the Commission finds that it is unjust and unreasonable to allow GFAs that are subject to a just and reasonable standard of review to remain outside the Midwest ISO Energy Markets."

GFA Rehearing Order at P 88 (JA 542) (quoting GFA Order at P 137 (JA 365)).

VI. The Responsible Entity and Scheduling Entity Designations Were Appropriate.

Transmission Owning Petitioners argue that the Commission should not have affirmed the ALJs' designation of the Northern States Power Companies as the GFA Responsible Entity and the GFA Scheduling Entity for their grandfathered agreements based on those companies' market participant status. Instead, Transmission Owning Petitioners aver (Br. at 28-34) that, consistent with cost causation principles, the grandfathered customers should have these roles. Their arguments are unpersuasive. The Commission used different reasoning to find that transmission owners should be the GFA Responsible Entity, GFA Order at P 161-62 (JA 368-69), and its conclusion is logical and reasonable for several reasons.

First, as the Commission indicated, and as Transmission Owning Petitioners explain, transmission owners take service under the Midwest ISO Tariff, and then they provide service to grandfathered customers on a back-to-back basis under the grandfathered agreements. *Id.* P 161 (JA 368-69); Br. at 12. This contractual arrangement is required by the Transmission Owners Agreement:

> Each Transmission Owner, to the extent it is a Load Serving Entity, shall take Network Integration Transmission Service or Point-to-Point Transmission Service from the Midwest ISO in accordance with the Tariff . . . for . . . load being served at wholesale under a Grandfathered Agreement. Each Transmission Owner that is a Load Serving Entity shall enter into a service agreement(s) under the Tariff with the Midwest ISO for such Transmission Service.

Transmission Owners Agreement at App. C, section II.A.3.f (FERC Br. Addendum at A-21); GFA Order at P 161 (JA 368). As such, the transmission owners, not the grandfathered customers, transact with the Midwest ISO with regard to transmission service for grandfathered load.

Not all grandfathered customers are market participants. GFA Order at P 152 (JA 367). The Tariff affirmatively (and logically) requires that the GFA Responsible Entity be a market participant. Procedural Order at P 19 n.23 (JA 4). For all these reasons, transmission owners are best situated to transact with the Midwest ISO regarding energy market-related charges such as "Market Activities charges, Schedule 16 and 17 charges, Transmission Usage Charges and debits or credits associated with FTRs held by the GFA Responsible Entity." *Id.*

Second, as this Court and the Commission have made clear, transmission owners are permitted to recover some energy market-related costs from their grandfathered customers, even those with grandfathered agreements subject to the *Mobile-Sierra* standard of review. *Midwest ISO Transmission Owners v. FERC,* 373 F.3d at 1370-71 (Schedule 10 costs); GFA Rehearing Order at P 148-49 (Schedule 17 costs) (JA 551-52). "[T]he terms and conditions of GFA subject to a just and reasonable standard of review allow the parties to propose appropriate modifications to reflect such new costs." GFA Order at P 138 (JA 365). Some transmission owners have already modified their grandfathered agreements to effectuate this. *See, e.g.*, *Transmission Owners of the Midwest Independent System Operator, Inc.*, 110 FERC ¶ 61,339 (2005), *order on reh'g*, 113 FERC ¶ 61,122 (2005), *appeal pending*, *East Kentucky Power Cooperative v. FERC*, D.C. Cir. No 06-1003 (filed Jan. 3, 2006). And in fact, Petitioner Xcel Energy Services, Inc. has made a filing to amend grandfathered agreements including GFA No. 377, about which it argues here. *Xcel Energy Services, Inc.*, 111 FERC ¶ 61,206 (2005); *partial uncontested settlement accepted*, 117 FERC ¶ 61,102 (2006).

Finally, Transmission Owning Petitioners do not argue that their grandfathered agreements are no longer profitable, nor do they mention that the energy markets have offsetting benefits that accrue to all users, including those with grandfathered load. *Midwest ISO Transmission Owners v. FERC*, 373 F.3d at 1369-71. As the Commission found, the benefits of the energy markets outweigh the increased costs for transmission owners. *See* GFA Order at P 100 ("Because implementing the [Tariff] even with a GFA carve-out will still expand the use of economic dispatch, aggregate costs under the new Day 2 markets should still be less than under the status quo Day 1 markets and the overall efficiency of the market would improve.") (JA 358-59).

CONCLUSION

For the reasons stated, the Commission's orders should be upheld in all respects.

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Wisconsin Public Power, Inc., et al. v. FERC **Docket Nos. ER04-691**
D.C. Cir. No. 04-1414, *et al.* **EL04-104**

CERTIFICATE OF COMPLIANCE

In accordance with Fed. R. App. P. 32(a)(7)(C)(i), I certify that the Brief of Respondent Federal Energy Regulatory Commission contains 20,931 words, not including the tables of contents and authorities, the certificates of counsel and the addendum.

____

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