Nos. 13-443, -445

In the Supreme Court of the United States

MICHIGAN ATTORNEY GENERAL BILL SHUETTE, ET AL.,
Petitioners,
v.
FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

HOOSIER ENERGY RURAL ELECTRIC
COOPERATIVE, INC., ET AL.,
Petitioners,
v.
FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

On Petitions for Writ of Certiorari to the United States Court of Appeals for the Seventh Circuit

BRIEF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. AND MIDWEST ISO TRANSMISSION OWNERS IN OPPOSITION

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QUESTIONS PRESENTED

1. Whether the United States Court of Appeals for the Seventh Circuit's ("Seventh Circuit") decision is consistent with decisions of this Court and other courts of appeals, which afford considerable discretion in how the Federal Energy Regulatory Commission ("FERC" or "Commission") makes its ratemaking determinations but hold that FERC must support with substantial evidence its conclusion that broad, system-wide benefits of new transmission facilities support broad, system-wide allocation of their costs.

2. Whether the Seventh Circuit's decision affirming FERC's decision not to hold a formal evidentiary hearing and FERC's reliance on certain evidence is consistent with the decisions of the other courts of appeal and relevant law, when the parties had the ability to review and challenge that evidence, and FERC had multiple bases for affirming the cost allocation proposal.

PARTIES TO THE PROCEEDING

Except as discussed below, the Midcontinent Independent System Operator, Inc. ("MISO") and the Midwest ISO Transmission Owners concur on the list of parties to the proceeding contained in the Petitions.[1] With respect to the list of parties contained in the Hoosier Petition (at iii-iv), MISO and the Midwest ISO Transmission Owners note that ALLETE, Incorporated, Ameren Illinois Company, d/b/a Ameren Illinois, Ameren Transmission Company of Illinois, and Great River Energy participated as part of the Midwest ISO Transmission Owners. In addition, prior to April 26, 2013, the Midcontinent Independent System Operator, Inc. was known as the Midwest Independent Transmission System Operator, Inc.

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[1] The first petition, in Case No. 13-443 ("Michigan Petition"), was brought by Michigan Attorney General Bill Shuette and other Michigan parties ("Michigan Petitioners"). The second petition, in Case No. 13-445 ("Hoosier Petition"), was brought by Hoosier Energy Rural Electric Cooperative, Inc., other public and investor-owned power companies, and industrial end-users ("Hoosier Petitioners"). Collectively, the Michigan Petition and Hoosier Petition are referred to as the "Petitions" and the Michigan Petitioners and Hoosier Petitioners are referred to as the "Petitioners."

CORPORATE DISCLOSURE STATEMENTS

Pursuant to Supreme Court Rule 29.6, MISO and the Midwest ISO Transmission Owners provide the following corporate disclosure statements.

A. The Midcontinent Independent System Operator, Inc.:

MISO states that it is a Delaware, non-stock, not-for-profit corporation that has no equity or stock.

B. The Midwest ISO Transmission Owners:

For the purposes of this filing, the Midwest ISO Transmission Owners include: Ameren Services Company ("Ameren Services"), as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois; Great River Energy; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; and Southern Minnesota Municipal Power Agency.

Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois

Ameren Services is a corporation organized and existing under the laws of the State of Missouri with its principal place of business in St. Louis, Missouri. Ameren Services is a wholly-owned subsidiary of Ameren Corporation ("Ameren") that provides administrative support services to Ameren and its operating companies, subsidiaries, and affiliates. Union Electric Company, d/b/a Ameren Missouri, Ameren Illinois Company, d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois are all wholly-owned subsidiaries of Ameren. No publicly held company has a 10% or greater ownership interest in Ameren.

Great River Energy

Great River Energy ("GRE") is a non-stock generation and transmission Cooperative Corporation organized under the laws of the state of Minnesota that supplies the majority of the electric requirements for twenty-eight (28) member distribution cooperatives in Minnesota and Wisconsin. GRE does not have a parent corporation and has not issued shares to the public. No publicly held company has a 10% or greater ownership interest in GRE.

Minnesota Power (and its subsidiary Superior Water, Light & Power Company)

ALLETE, Inc., d/b/a Minnesota Power is a Minnesota public utility company, which also owns

Superior Water, Light & Power Company, a Wisconsin public utility company. No publicly held company has a 10% or greater ownership interest in ALLETE, Inc.

Montana-Dakota Utilities Co.

Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc. ("MDU"), a Delaware corporation. No publicly held company has a 10% or greater ownership interest in MDU.

Northern Indiana Public Service Company

Northern Indiana Public Service Company ("NIPSCO") is an Indiana corporation engaged in the generation, transmission, and distribution of energy at wholesale and retail. NIPSCO is a wholly-owned subsidiary of NiSource Inc. No publicly held company has a 10% or greater ownership interest in NIPSCO.

Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.

Northern States Power Company, a Minnesota corporation and Northern States Power Company, a Wisconsin corporation, are combination electric and natural gas public utilities and wholly-owned utility operating company subsidiaries of Xcel Energy Inc.[2] No publicly held company owns 10% or more of Xcel Energy Inc. stock.

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[2] The other public utility operating company subsidiaries of Xcel Energy Inc. are Public Service Company of Colorado and Southwestern Public Service Company.

Northwestern Wisconsin Electric Company

Northwestern Wisconsin Electric Company ("NWE") is an investor-owned utility. No corporation, partnership or business trust owns a controlling interest in NWE. No publicly held corporation owns of record, or to NWE's knowledge owns beneficially, 10% or more of NWE's common stock.

Otter Tail Power Company

Otter Tail Power Company ("Otter Tail") is an electric utility providing electrical service to customers in Minnesota, North Dakota, and South Dakota. Otter Tail is a wholly-owned subsidiary of Otter Tail Corporation, an investor-owned company. Otter Tail Corporation does not have any parent companies and no publicly held corporation has a 10% or greater ownership interest in Otter Tail Corporation.

Southern Minnesota Municipal Power Agency

Southern Minnesota Municipal Power Agency ("SMMPA") is a joint action agency comprised of 18 member municipalities in Minnesota, which own and operate municipal electric systems. SMMPA is a non-profit political subdivision of the State of Minnesota organized under Chapter 453 of the Minnesota Statutes. SMMPA functions as the principal power supplier for its 18 members. No publicly held company has a 10% or greater ownership interest in SMMPA.

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OPINION BELOW

The opinion of the Seventh Circuit in *Illinois Commerce Commission v. FERC* (“*ICC II*”), was issued on June 7, 2013, and is reported at 721 F.3d 764. The opinion is reproduced in the appendix to the Hoosier Petition (“Hoosier App.”) at 1-25. The initial FERC order, issued on December 16, 2010, *Midwest Independent Transmission System Operator, Inc.* (“MVP Order”), is reported at 133 FERC ¶ 61,221 (2010). Hoosier App. 334-647. FERC’s October 21, 2011 order on rehearing, *Midwest Independent Transmission System Operator, Inc.* (“MVP Rehearing Order,” and with the MVP Order, the “MVP Orders”), is reported at 137 FERC ¶ 61,074 (2011). Hoosier App. 26-333.

JURISDICTION

The judgment of the Seventh Circuit was entered on June 7, 2013. The jurisdiction of this Court is invoked under 28 U.S.C. § 1254(1).

STATEMENT OF THE CASE

These proceedings involve two nearly identical petitions for a writ of certiorari to review a decision of the Seventh Circuit that affirmed (as relevant here) orders of the Commission that approved tariff rules for broad regional recovery of the costs of new electric transmission facilities that satisfy express tariff standards for regional (as opposed to local) benefits.

A. Statutory and Regulatory Background

Section 201(b)(1) of the Federal Power Act (“FPA”), 16 U.S.C. § 824(b)(1), provides FERC with exclusive jurisdiction over the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce.

The FPA requires that all rates, terms, and conditions for such transmission and wholesales be "just and reasonable." FPA § 205(a), 16 U.S.C. § 824d(a). The FPA does not define the terms "just and reasonable," and the courts have made it clear there is no exact, formulaic method of deciding what is just and reasonable. *See Morgan Stanley Captial Grp. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 532 (2008) (observing that the Supreme Court has "repeatedly emphasized that the Commission is not bound to any one ratemaking formula") (citations omitted); *Colo. Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945) ("Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.") (citation omitted); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004) ("*MISO TOs*") ("[N]ot surprisingly, we have never required a ratemaking agency to allocate costs with exacting precision.") (citation omitted); *Sithe / Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002) ("FERC is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly.") (citation omitted). Courts afford FERC particular deference on these ratemaking determinations. *Morgan Stanley*, 554 U.S. at 532 ("[The Court] afford[s] great deference to [FERC] in its rate decisions.") (citations omitted); *Permian Basin Area Rate Cases*, 390 U.S. 747, 790 (1968) (reiterating that deference to FERC ratemaking is appropriate because of "the breadth and complexity of the Commission's responsibilities"); *Sacramento*

Mun. Util. Dist. v. FERC, 616 F.3d 520, 528 (D.C. Cir. 2010) ("*SMUD*") ("In matters of ratemaking, our review is highly deferential, as [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.") (alteration in original) (quoting *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009) (internal quote marks and citation omitted)).

As the Hoosier Petitioners note, Hoosier Petition at 5, the electric industry has undergone significant changes since enactment of the FPA. Changes in technology have lowered the costs of generating electricity and transmitting power over longer distances. *See Morgan Stanley*, 554 U.S. at 535-36. FERC, in furtherance of its statutory responsibilities, has encouraged the development of regional transmission organizations ("RTOs") such as MISO to facilitate competition, increase reliability, and encourage regional transmission planning. *Regional Transmission Organizations*, Order No. 2000, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089, at 31,163 (1999) (establishing minimum criteria for an RTO, and decreeing that an RTO must have "ultimate responsibility" for planning, directing, and arranging the transmission expansions and upgrades needed in its region to enable the RTO "to provide efficient, reliable and non-discriminatory service"), *order on reh'g*, Order No. 2000-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092, at 31,380-81 (2000), *petitions for review dismissed sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). RTOs like MISO can bring particular benefits through a regional approach to planning transmission system upgrades, because evaluating transmission alternatives "at the regional level" helps meet the region's needs "more efficiently or cost-effectively than solutions identified in the local transmission plans." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, III FERC Stats. & Regs., Regs. Preambles ¶ 31,323, at P 68 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012). FERC has previously found that MISO's regional planning process will provide these benefits, i.e., its "unified planning" of "the regional grid" should result in "more efficient [transmission] siting . . . that follows need rather than arbitrary boundaries such as individual local service territories." *Midwest Indep. Transmission Sys. Operator, Inc*. Opinion No. 453, 97 FERC ¶ 61,033 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141, at 61,412 (2002) ("Opinion No. 453-A"), *order on remand*, 102 FERC ¶ 61,192, *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom. Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004). The United States Court of Appeals for the District of Columbia ("D.C. Circuit") has already agreed that MISO's "large scale regional coordination and planning" should "redound to all users of the transmission grid." *MISO TOs*, 373 F.3d at 1371 (citation omitted) (internal quotation marks omitted).

Congress also recognized the need for and benefits of increased transmission investment and participation in RTOs or similar organizations in enacting the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) ("EPAct 2005"), in which it amended the FPA to allow for incentives for investment in transmission infrastructure and participation in RTOs. EPAct 2005 § 1241 (modifying FPA § 219) (codified at 16 U.S.C. § 824s); *see also Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,222, at P 1 (noting that EPAct 2005 reflects a Congressional determination of the need for "transmission infrastructure investment that will help ensure the reliability of the bulk power transmission system in the United States and reduce the cost of delivered power to customers by reducing transmission congestion"), *order on reh'g*, Order No. 679-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,236 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

B. The MVP Filing and the FERC Orders

On July 15, 2010, MISO and the Midwest ISO Transmission Owners (the "MVP Applicants") submitted their proposal to adopt system-wide cost allocation for major transmission enhancements (to be known as Multi-Value Projects ("MVPs")) determined through MISO's regional planning process to satisfy proposed tariff criteria for identifying regionally beneficial projects ("MVP Filing"). *See* Appendix of Respondents Midcontinent Independent System Operator, Inc. and Midwest ISO Transmission Owners ("MISO App.") at 1-4 (MVP Filing Letter, reproduced in MISO App. at 1-82); *see also* MVP Order, P 1, Hoosier App. 334-37. MISO's pre-existing cost allocation methodologies made no provision for recovering on a system-wide basis all the costs of a MISO-planned transmission upgrade, regardless of the extent to which the upgrade provided an overall system benefit. MISO

App. 7-12 (MVP Filing Letter); MVP Order, PP 10, 12-13, Hoosier App. 343-46.

The MVP Filing was the result of months of negotiations among MISO, its transmission owners, affected state commissions, and other stakeholders. MISO App. 13-20 (MVP Filing Letter), MISO App. 118-24 (Prepared Direct Testimony of Jennifer Curran on Behalf of the Midwest Independent Transmission System Operator, Inc. ("Curran Testimony"), reproduced at MISO App. 102-49)). In the MVP Filing, the MVP Applicants proposed to create a new category of projects—MVPs—and to allocate the costs of such projects to all customers taking service under MISO's open access transmission tariff. MISO App. 1-3, 44-46 (MVP Filing Letter), 105-17 (Curran Testimony). While the proposal was intended in part to facilitate the interconnection of wind and other renewable resources, it was also intended to provide a means to incent and pay for the construction of new transmission facilities to address multiple reliability needs and provide economic benefits on a regional scale. MISO App. 34 (MVP Filing Letter). The MVP Filing posited that when transmission upgrades offer regional benefits, it is reasonable to allocate the costs on a regional basis to all users of the MISO transmission system, rather than only to those transmission customers that happen to be located in the small subset of the MISO region (i.e., the "zone") where the particular transmission facilities would be located. MISO App. 3-7, 24-25 (MVP Filing Letter), 107-10 (Curran Testimony); MVP Order, PP 27-28, Hoosier App. 353-55.

The filing established three sets of criteria under which a project could be designated as an MVP upon approval by the MISO Board of Directors: (1) Criterion 1 – a Criterion 1 MVP must be developed through MISO's regional transmission expansion planning process for the purpose of enabling the MISO transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation, and must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade; (2) Criterion 2 – a Criterion 2 MVP must provide multiple types of economic value across multiple pricing zones with a benefit-to-cost ratio as set forth in the tariff; and (3) Criterion 3 – a Criterion 3 MVP must address at least one transmission issue associated with a projected violation of a North American Electric Reliability Corporation or Regional Entity standard and at least one economic-based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs as set forth in the tariff. MISO App. 38-39 (MVP Filing Letter), 136-37 (Curran Testimony). Thus, a project can be designated as an MVP only if it meets certain reliability and economic benefit criteria. As indicated above, even a project that is approved as advancing public policy objectives under Criterion 1 must satisfy economic or reliability criteria. MVPs also must meet certain minimum voltage and cost thresholds to help further distinguish them from merely local projects, and cannot be constructed solely in response to an individual request for transmission service or an individual generator interconnection request. MISO App. 41-42 (MVP Filing Letter), 136-40 (Curran Testimony).

While the MVP Filing sought approval only for an MVP identification process, rather than approval of individual MVPs, the MVP Filing included analyses of various previously identified projects of a type that would be expected to qualify as MVPs, and showed that these representative MVP-type projects would deliver between $400 million and $1.3 billion in annual economic benefits starting in 2015, spread almost evenly among MISO subregions. MISO App. 28-29 (MVP Filing Letter), MISO App. 96-97 (Prepared Direct Testimony of John Lawhorn Filed on Behalf of the Midwest Independent Transmission System Operator, Inc. ("Lawhorn Testimony"), reproduced in MISO App. at 83-101); *see also* MVP Order, PP 34-35, Hoosier App. 359-360. While the underlying detailed studies were not themselves included with the filing, many of the studies were publicly available, and the MVP Applicants provided links to the studies in their filings. *See* MISO App. 15-18 (MVP Filing Letter); MVP Order, PP 168 n.211, 210 n.270, Hoosier App. 432-33, 461.

After notice and an extended comment period, FERC generally approved the MVP cost allocation methodology, finding that the MVP proposal provides "a functional approach to transmission planning—a package of processes that is intended to enable the development of transmission facilities that will increase the reliable and economic improvement of the transmission system, and support policy initiatives that drive transmission planning processes." MVP Order, P 193, Hoosier App. 449-50.

For further assurance that the benefits of approved MVPs would be broadly distributed throughout MISO, FERC required MISO to evaluate and approve groups of MVPs on a "portfolio" basis. MVP Order, P 221, Hoosier App. 469-70. FERC also required MISO to submit annual informational reports describing the selection of MVP facilities and work with its stakeholders to assess the achievements and shortcomings of the MVP selection process. MVP Order, P 243, Hoosier App. 483. FERC generally upheld these determinations in its order on rehearing. *See* MVP Rehearing Order, PP 112-97, 210-14, Hoosier App. 113-93, 200-05.

C. The Seventh Circuit's Decision

The court in *ICC II* affirmed FERC on all issues that are relevant here. The court found that FERC appropriately determined that MVPs are not "local" facilities, and that as part of an integrated transmission grid, will support and benefit all users of that grid. *ICC II* at 779-80, Hoosier App. 23. The court found that FERC acted properly in making an interim cost allocation methodology permanent, and that the MVP Orders did not intrude inappropriately on state authority. *ICC II* at 773, Hoosier App. 8-9. The court also held FERC acted appropriately in basing its decision on evidence that was subject to review and challenge by the parties and in not instituting an evidentiary hearing or formal, trial-type discovery procedures. *ICC II* at 775-76, Hoosier App. 13-16.

REASONS FOR DENYING THE PETITIONS

Under this Court's rules, a petition for a writ of certiorari "will be granted only for compelling reasons," such as, for example, when a federal appeals court "has entered a decision in conflict with the decision of another [federal] court of appeals . . . on the same important matter."[3] The Court's rules caution that "[a] petition for a writ of certiorari is rarely granted when the asserted error consists of erroneous factual findings or the misapplication of a properly stated rule of law."[4]

No such "compelling reasons" are evident here. The Petitioners assert that the Seventh Circuit's decision "opens a circuit split" on both interpretation of the FPA's "just and reasonable" standard and when FERC must conduct a trial-type evidentiary hearing. Hoosier Petition at 2, Michigan Petition at 16, 21. But there is no such split, on either question. The Seventh Circuit applied the same well-established standards that are enforced by the other circuits.

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[3] Sup. Ct. R. 10. A writ of certiorari may also be warranted when a federal appeals court "has so far departed from the accepted and usual course of judicial proceedings . . . as to call for an exercise ofthis Court's supervisory power" or "has decided an important question of federal law that has not been, but should be, settled by this Court, or has decided an important federal question in a way that conflicts with relevant decisions of this Court." *Id.* Petitioners here do not appear to seek certiorari on any of these grounds.

[4] *Id.*

A. The Seventh Circuit Applied the Same Cost Causation Standard as the Other Circuit Courts of Appeals

Under section 205 of the FPA, FERC is required to ensure that the rates, terms, and conditions for transmission of electricity in interstate commerce are just, reasonable, and not unduly discriminatory or preferential. 16 U.S.C. § 824d. In applying this mandate, FERC and the courts have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the cost causation principle, i.e., the requirement that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them." *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992).

The D.C. Circuit has explained that the courts "evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party" but "have never required a ratemaking agency to allocate costs with exacting precision." *MISO TOs*, 373 F.3d at 1368-69 (citing *Sithe*, 285 F.3d at 5). Rather, "[i]t is enough, given the standard of review under the APA, that the cost allocation mechanism not be 'arbitrary or capricious' in light of the burdens imposed or benefits received." *Id.* at 1369.

The Michigan Petitioners contend that the Seventh Circuit "departed from and significantly diluted" the established cost causation principle "in a way that conflicts with previous decisions of the D.C. Circuit." Michigan Petition at 16. The Hoosier Petitioners proclaim that the Seventh Circuit's decision "eviscerates the cost causation principle" and "conflicts with a wall of D.C. Circuit precedents." Hoosier Petition at 20.

Despite this rhetoric, Petitioners face a fundamental obstacle: on its face, the Seventh Circuit's decision approvingly cites and follows the cost-causation and other precedents and principles of the D.C. Circuit; it neither critiques, rejects, nor distinguishes any of those precedents and principles. *ICC II* at 773, 776, Hoosier App. 9, 15-16. Nor can the Petitioners cite to any decision of any other circuit that confronts the same question—region-wide cost recovery of RTO-planned regional facilities—and comes to an opposite conclusion. Indeed, the most prominent decision addressing a comparable question was by the Seventh Circuit itself—and was authored by the same celebrated jurist as the present decision. *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009) ("*ICC I*") (finding that FERC had not offered sufficient justification for charging all loads in an RTO for the cost of extra-high-voltage "backbone" transmission lines). Thus, none of the circumstances one might expect to find with conflicting decisions are evident here. As shown below, there is no conflict.

1. The Seventh Circuit did not establish a new cost causation standard.

The Seventh Circuit did not seek to blaze a new trail in FERC ratemaking; rather, it simply applied the teachings from its own cases and those of other circuits on the balancing of costs and benefits. Under the cost causation principle, FERC must ensure that the costs allocated to beneficiaries are at least roughly commensurate with the benefits that are expected to accrue to those parties. *ICC I*, 576 F.3d at 476-77 ("If

[FERC] cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East . . . but has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; [FERC] can approve PJM's proposed pricing scheme on that basis."). *See also MISO TOs*, 373 F.3d at 1369 ("[N]ot surprisingly, we have never required a ratemaking agency to allocate costs with exacting precision.") (citation omitted); *Sithe*, 285 F.3d at 5 ("FERC is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly.") (citation omitted).

These principles often have been applied to find that an integrated transmission network, such as MISO's, provides some benefits to all users of the network. *See W. Mass. Elec. Co. v. FERC*, 165 F.3d 922, 927-28 (D.C. Cir. 1999) (approving "rolled-in" pricing that charges facility costs to all grid users as "part of a consistent policy to assign the costs of system-wide benefits to all customers on an integrated transmission grid"); *Me. Pub. Serv. Co. v. FERC*, 964 F.2d 5, 8 (D.C. Cir. 1992) (affirming the use of rolled-in pricing and noting FERC's "longstanding policy in favor of rolled-in rates for integrated systems") (citation omitted). As FERC has explained:

> Rolled-in pricing is appropriate when the relevant facilities are integrated into the transmission network. This pricing is appropriate because it spreads the cost of

> network facilities across the entire network; as part of the network, the added facilities benefit all users of the network and thus their costs should be shared among all users of the network.

S. Co. Servs., Inc., 116 FERC ¶ 61,247, at P 17 (2006) (footnote omitted).

Similarly, FERC allocated the administrative costs of maintaining MISO as a regional grid operator to *all* loads in MISO, citing "the benefits all users of the regional grid will receive when that grid is operated and planned by a single regional entity instead of multiple local entities whose goals may often conflict." Opinion No. 453-A at 61,412. FERC found that this "unified planning and operation of the regional grid" should result in "more efficient siting of transmission facilities from the regional perspective; i.e., siting that follows need rather than arbitrary boundaries such as individual local service territories." *Id.* Affirming that region-wide cost allocation, the D.C. Circuit cited MISO's "large scale regional coordination and planning of transmission [that] would redound to all users of the transmission grid." *MISO TOs*, 373 F.3d at 1371 (citation omitted) (internal quotation marks omitted).

Nothing in the precedent bars FERC from assessing the match between costs and benefits at *a collective level*, e.g., at a zonal level or an RTO region-wide level. In balancing costs and benefits, the scope of the use and benefits can support an equivalent scope of cost recovery. The cases discussed above that permitted rolled-in pricing for "integrated" facilities or that approved MISO region-wide recovery of the costs of maintaining the MISO as a regional transmission organization plainly show this principle in action, i.e., matching system-wide or region-wide benefits with system-wide or region-wide cost recovery.

Whether at an individual or regional basis, FERC's conclusion that benefits are roughly commensurate with costs may not be arbitrary and capricious, i.e., it must be supported by substantial evidence.[5] The D.C. Circuit recognized this in *MISO TOs*, by way of noting the relatively forgiving arbitrary and capricious standard that governs court review of FERC's exercise in comparing costs and benefits. *MISO TOs*, 373 F.3d at 1368. The Seventh Circuit similarly recognized this in *ICC I*, finding that FERC had failed to support the essential connection between costs and benefits, because the agency had presented no particulars regarding the contribution that high-voltage facilities are likely to make to the reliability of the network or "even the roughest estimate of likely benefits to the objecting utilities." *ICC I*, 576 F.3d at 474-75.

In short, the precedents of the D.C. Circuit, the Seventh Circuit, and the other circuits chart a consistent path: FERC must offer substantial evidence in support of the proposition that cost allocation for facilities reasonably matches the expected benefits from and use of those facilities. FERC must make at least a rough approximation of benefits and articulate a plausible reason why the costs match those benefits. FERC satisfied those requirements here, and the

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[5] "Substantial evidence" is that which a reasonable mind might accept as adequate to support a conclusion. *SMUD*, 616 F.3d at 529; *Cal. ex rel Lockyer v. FERC*, 329 F.3d 700, 714 n.15 (9th Cir. 2003).

Seventh Circuit properly found that FERC had appropriately exercised its ratemaking discretion in this case, consistent with precedent from other circuits.

2. FERC's conclusion that regional benefits warranted regional cost recovery was supported by substantial evidence.

As shown above, relevant precedent did not bar FERC from finding that MVP costs can be recovered on a regional basis if MVPs provide regional benefits, nor did relevant precedent bar the Seventh Circuit from accepting such an analysis by FERC. Ultimately, then, the question before the Seventh Circuit was whether substantial evidence supported FERC's conclusion that MVPs would provide broad system benefits such that their costs could be recovered on a system-wide basis. The record before FERC provided ample evidence to support that conclusion.

In reviewing that record, it is important to remember that the filing before FERC did not seek approval of specific MVP transmission upgrades; rather, FERC was asked to accept a set of tariff rules that contained standards, procedures, and safeguards to govern MISO's identification of major transmission upgrades with the scope, characteristics, and benefits that would warrant their recovery on a system-wide basis. The proposed tariff terms and conditions, with additional safeguards ordered by FERC, provided that assurance.

First, the proposed tariff rules permit transmission projects to qualify as MVPs (i.e., to have their costs allocated to all MISO loads) only if they pass various scope, cost, and functional benefit or purpose tests, which identify projects that provide regional benefits, as opposed to those that are more local in nature. MISO App. 38-42 (MVP Filing Letter); MVP Order, P 207, Hoosier App. 459; MVP Rehearing Order, PP 132-34, Hoosier App. 132-37. All MVPs must exceed certain minimum size and cost thresholds, and may not include projects driven solely by an individual request for transmission service or an individual generator interconnection request. MISO App. 39-40 (MVP Filing Letter). In addition, as described above, each project must meet one of three criteria designed to identify projects that provide regional reliability, economic, or public policy benefits sufficient to be classified as MVPs.

Second, the tariff requires that MISO consider and approve MVPs on a "portfolio" basis, further ensuring that transmission that is paid for across the MISO region will provide benefits across the MISO region. Under the portfolio approach, MISO will "move forward MVPs in appropriate numbers, at appropriate times, in order to maximize regional benefits and to ensure that the costs of each portfolio are widely and fairly distributed." MVP Order, P 194, Hoosier App. 450.

Third, transmission projects can become MVPs only if they are a product of MISO's open and transparent regional planning process, with opportunities for stakeholder input into which projects are designated as MVPs. MISO App. 110-11 (Curran Testimony); *see also* MVP Order, P 207, Hoosier App. 459; MVP Rehearing Order, PP 132, 142, Hoosier App. 132-33, 142-43. MVPs will be identified and approved through MISO's open and transparent transmission planning process, in which stakeholder viewpoints on the relative benefits of proposed projects and whether they should qualify as MVPs will be considered, as required by FERC's Order No. 890. *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241, at P 435, *order on reh'g*, Order No. 890-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *see also* MVP Order, PP 224-26, Hoosier App. 472-73; MVP Rehearing Order, P 142, Hoosier App. 142-43. That open process can take into account, "among other factors, the relative costs of generation capacity and transmission expansion," MISO App. 141 (Curran Testimony), allowing parties to assess whether a proposed transmission project truly is the most cost-effective solution overall for the region.

Fourth, MISO's transmission usage study demonstrated that MVP-type facilities would be used predominantly on a *regional* (as opposed to local) basis. MVP Order, P 238, Hoosier App. 479; MVP Rehearing Order, P 129, Hoosier App. 128-30. As explained in the MVP Filing, MISO conducted transmission usage studies on various MVP-type projects that had been identified in previous planning studies to determine the extent to which those transmission upgrades would be used on a regional, rather than local, basis. *See* MISO App. 28-32 (MVP Filing Letter), 133-35 (Curran Testimony). The study, which included over two hundred extra-high voltage transmission facilities, indicated that the evaluated projects would be used overwhelmingly (i.e., 80%) on a regional basis. MISO App. 134-35 (Curran Testimony). As almost any transmission improvement project necessarily will be used locally to some extent, the indicated very high level of regional usage "underscores that these types of facilities are essentially for the purpose of strengthening the regional transmission system, for the use and benefit of all market participants that use the regional grid." MISO App. 135 (Curran Testimony).

Fifth, FERC had evidence that the regional benefits of a representative group of MVP "starter projects" would equal or outweigh their costs to the region. MISO App. 28-32 (MVP Filing Letter), 96-100 (Lawhorn Testimony), 126-28 (Curran Testimony); MVP Order, P 229, Hoosier App. 474-75; MVP Rehearing Order, P 127, Hoosier App. 126-27. As explained above, the MVP Filing did not itself propose specific projects as MVPs, but instead proposed criteria, procedures, and safeguards to identify projects offering regional benefits. The MVP Filing did, however, include substantial analysis on an initial set of MVP starter projects, which reinforced the conclusion that MVPs can be expected to provide broad net economic and reliability benefits to the region.

Specifically, MISO evaluated and quantified the economic benefits associated with a group of MVP-type transmission projects that had been identified through prior planning studies. This group of MVP starter projects included transmission lines in every zone in the MISO region. MISO App. 28-29 (MVP Filing Letter), 127 (Curran Testimony). MISO estimated, and FERC agreed, that these MVP starter projects would deliver between $582 million and $798 million in quantifiable economic benefits each year. MVP Order, P 229, Hoosier App. 474-75. These quantifiable economic benefits included: (i) $400 million to $1.3 billion in aggregate annual adjusted production cost savings, MISO App. 28-29 (MVP Filing Letter), 97 (Lawhorn Testimony), 128-29 (Curran Testimony); (ii) an annual reduction of approximately 2,000,000 megawatt-hours in transmission system losses, yielding $104 million of additional savings to loads that ultimately bear the costs of energy lost during transmission, MISO App. 30 (MVP Filing Letter), 99 (Lawhorn Testimony), 129 (Curran Testimony); (iii) an estimated additional $110 million savings from deferred capacity investment resulting from reduced transmission system losses, MISO App. 30 (MVP Filing Letter), 99 (Lawhorn Testimony), 129 (Curran Testimony); and (iv) a reduction in MISO's Planning Reserve Margin, where, even a relatively small reduction of 0.5% in the installed reserve percentage would result in the deferral of about 500 megawatts of generation capacity investment, saving approximately $500 million, MISO App. 30 (MVP Filing Letter), 130-31 (Curran Testimony). *See also* MVP Order, PP 229 & n.287, 230, 232, Hoosier App. 474-76.

In contrast to these quantifiable annual benefits of between $582 million and $798 million, the MVP starter projects were estimated to cost ratepayers $675 million each year. MVP Order, P 233, Hoosier App. 476. While that analysis already indicates that costs and benefits would be roughly commensurate, it does not include other benefits that are more difficult to quantify, such as enhancing grid reliability and facilitating satisfaction of state policy mandates and goals like renewable portfolio standards. MISO App. 132-33 (Curran Testimony); MVP Order, P 202, Hoosier App. 456; MVP Rehearing Order, P 131, Hoosier App. 131-32. Therefore, the record before FERC contained substantial evidence that projects of the type expected to qualify as MVPs will yield concrete, quantifiable benefits commensurate with their expected costs, and benefits greater than those costs when other, less easily quantifiable benefits also are considered. These benefits will inure to all users of the MISO grid.

Sixth, FERC ordered MISO to prepare and post annual and triennial reports for its MVP program, finding that "these reviews will provide an additional safeguard that ensures that the MVP methodology is working as expected, informs stakeholder decisions regarding future transmission plans, and provides a basis for any potential adjustments to the allocation of the costs associated with those MVPs." MVP Rehearing Order, P 190, Hoosier App. 188. This reporting requirement therefore goes to the heart of whether the cost-benefit balance that justifies region-wide cost allocation is in fact being realized.

FERC's conclusion that the MVP category of projects warrants broad regional cost recovery rested on each of these bases, and thus its decision to allow system-wide cost recovery for projects identified under these rules was supported by substantial evidence. The Seventh Circuit appropriately recognized this:

> Bear in mind that every multi-value project is to be large, is to consist of high-voltage transmission (enabling power to be transmitted efficiently across pricing zones) and is to help utilities satisfy renewable energy requirements,

> improve reliability (which benefits the entire regional grid by reducing the likelihood of brownouts or outages, which could occur anywhere on it), facilitate power flow to currently underserved areas in the MISO region or attain several of these goals at once. The 16 projects that have been authorized are just the beginning. And FERC has required MISO to provide annual updates on the status of these projects. Should the report show that the benefits anticipated by MISO and FERC are not being realized, the Commission can modify or rescind its approval of the MVP tariff.

ICC II at 774, Hoosier App. 10-11 (citation omitted) (also noting quantified benefits and contrasting with costs). Consequently, the Seventh Circuit did not create any new standards or reject any established standards. Rather, it simply confirmed that FERC complied with the accepted legal standards for finding a rate method "just and reasonable," including the cost causation principle.

3. The cases cited by Petitioners do not conflict with the Seventh Circuit's decision.

Petitioners cite a number of cases in their effort to paint the Seventh Circuit's decision as creating a split in the circuits on an important issue, but none of these cases demonstrates any such split.

Indeed, the first decision cited by Michigan Petitioners—*MISO TOs*—shows if anything consistent treatment by the D.C. Circuit and Seventh Circuit of a similar cost causation question. The D.C. Circuit's

MISO TOs decision affirms MISO-wide allocation of MISO's costs of maintaining a regional transmission organization; the Seventh Circuit decision affirms MISO-wide allocation of the costs of certain major new transmission facilities that MISO identifies and approves in its regional transmission planning process. Moreover, a critical factor that warranted region-wide allocation in *MISO TOs* also supports region-wide allocation in the present case. In *MISO TOs*, FERC found, and the D.C. Circuit agreed, that all MISO loads would benefit from MISO's transmission planning for the benefit of the region as a whole, in part through identification of new transmission facilities that were optimal from the regional perspective, as opposed to the narrower perspective of individual systems that made up MISO.[6] The MISO-wide benefits of this regional planning process justified recovering from all loads MISO's costs of administering that regional planning process. *The present case concerns the very fruits of that regional planning process,* i.e., certain new transmission facilities that MISO identifies through its regional planning process. FERC's finding in the present case, affirmed by the Seventh Circuit, that the costs of certain regionally beneficial transmission facilities can be allocated to all loads in the region follows naturally from the D.C. Circuit's

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[6] "[U]nified planning" of "the regional grid" should result in "more efficient [transmission] siting . . . that follows need rather than arbitrary boundaries such as individual local service territories." Opinion No. 453-A at 61,412. This "large scale regional coordination and planning" should "redound to all users of the transmission grid." *MISO TOs*, 373 F.3d at 1371 (citation omitted) (internal quotation marks omitted).

decision that MISO's administrative costs of *identifying* regionally beneficial transmission upgrades can be allocated to all loads in the region.

The other D.C. Circuit decision cited by Michigan Petitioners as cost allocation precedent, *Ala. Elec. Coop., Inc. v. FERC*, 684 F.2d 20 (D.C. Cir. 1982), did not in fact address whether a cost allocation methodology was just and reasonable. Rather, that decision addressed whether it was unduly discriminatory to charge the same rate to two different customer classes when the public utility's cost study showed that the rate would impose a significantly higher rate of return on one of the classes. *See Ala. Elec.*, 684 F.2d at 23. Notably, the court explained that the customary, and deferential, inquiry of whether a FERC-established rate falls within a "zone of reasonableness" did not govern that case because "rates may lie within the zone of reasonableness and yet result in undue prejudice." *Id.* at 27 (footnote omitted). Thus, the undue discrimination analysis in *Alabama Electric* provides little guidance on whether, in the first instance, a transmission facility has sufficient characteristics of system benefit such that its costs can be recovered from all users of the system.

For their part, the Hoosier Petitioners principally rely upon *Sithe* in service of their argument that the D.C. Circuit's application of the cost causation rule "demands an individualized, rather than broad-based inquiry." Hoosier Petition at 21. Hoosier Petitioners, however, overstate the holding in that case and ignore subsequent D.C. Circuit decisions accepting the very same rate treatment that *Sithe* had found insufficiently explained. If anything, *Sithe* and subsequent decisions show the considerable deference the D.C. Circuit affords FERC in cost allocation.

Sithe is one of several cases to grapple with a cost overcollection problem inherent in a marginal line loss charge, which charges every customer using a transmission line for losses on that line as if it were the marginal customer. *Sithe*, 285 F.3d at 3. Since not all customers are in fact marginal, the method charges customers in total for substantially more than the actual cost of losses on the line. *Id.* But since any customer using the line *could* be the marginal customer, FERC takes a firm position that simply refunding each transmission customer a pro rata share of the overcollections would defeat the incentive and price signaling purposes of using a marginal price in the first place. *Id.* at 5; *see also Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 235-36 (D.C. Cir. 2013). In *Sithe*, the court was faced with a concededly overcharged customer and only a "cursory" explanation from FERC of the countervailing pricing policy considerations. *Sithe*, 285 F.3d at 5. The *Sithe* court did not, however, as the Hoosier Petitioners contend (Hoosier Petition at 22), "vacate" FERC's marginal losses order, but rather "remand[ed] the case to [FERC] to more adequately respond to petitioner's contentions." *Sithe*, 285 F.3d at 5. In the more recent *Black Oak* decision, the D.C. Circuit addressed the same issue, but accepted FERC's pricing explanation—notwithstanding that this meant that customers that *paid* the line loss overcollection were *not* entitled to a refund of that overcollection.[7] The court's review involved not simply toting up costs and benefits to each customer but also "defer[ence] to FERC's policy priorities" recognizing that "[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." *Black Oak*, 725 F.3d at 240 (quoting and citing *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009)).

The Hoosier Petitioners also cite two Natural Gas Act cases arising under a similar "just and reasonable" rate standard, but both of those cases concerned only a failure of FERC to support system-wide cost allocation, rather than imposition of any requirement to assess costs and benefits on an individual customer basis. In *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305 (D.C. Cir. 1991), the court perceived FERC's position to be "that system-wide benefits exist primarily because the Commission says they do," and reminded FERC that "[a]n agency's unsupported assertion does not amount to substantial evidence." *Id.* at 1313. The court instructed FERC to identify "with reasonable particularity the system-wide benefits" that new facilities would bring in order to supply substantial evidence in support of "rolled-in" pricing.

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[7] *Black Oak*, 725 F.3d at 237-39. *Electricity Consumers Resource Council v. FERC*, 747 F.2d 1511 (D.C. Cir. 1984), also cited by the Hoosier Petitioners, is an even earlier marginal pricing decision, indeed, "our first in what will prove to be many applying the principles of marginal cost pricing theory to electricity rate design," *id.* at 1519 (MacKinnon, J., concurring), and thus a poor guide to the D.C. Circuit's present approach to the role of the cost causation principle in complex rate design issues.

Id. By contrast, as shown above, FERC in the present case had abundant support for its conclusion that MVPs will have regional benefits, including tariff criteria requiring such benefits, procedures (such as the "portfolio" approval approach, opportunities for stakeholder input, and reporting requirements) to help ensure that only regionally beneficial projects are afforded MVP status, and analysis of MVP-type projects quantifying their system benefits and indicating that they would be used predominantly on a regional basis.

Similarly, in *K N Energy,* the court found as a general matter that the considerable expense of "take-or-pay" contracts that pipelines had entered with their suppliers *could* be allocated to all of the pipeline's customers under the just and reasonable standard, but that the pipeline in that case had not justified the specific cost allocation it proposed. *K N Energy*, 968 F.2d at 1296, 1303-04.

In short, the Hoosier Petitioners' portrait of a wall of D.C. Circuit precedent demanding that FERC ratemaking adhere to an individualized balancing of the costs and benefits to each customer is not an accurate reflection of the D.C. Circuit's approach to review of FERC cost allocation orders. Like the Seventh Circuit, the D.C. Circuit applies the cost-causation principle in a pragmatic and deferential manner—even to the point of *already having approved* (in *MISO TOs*) a region-wide recovery of MISO costs when FERC articulates and supports a plausible rationale for that cost allocation.

Finally, the Michigan Petitioners cite to the Seventh Circuit's decision in *ICC I*. Michigan Petition at 17. Of course, as a Seventh Circuit decision, it cannot be said to be "a decision in conflict with the decision of another United States court of appeals on the same important matter." Sup. Ct. R. 10. Moreover, *ICC I*, viewed in conjunction with the present case, simply underscores that the Seventh Circuit approaches the cost causation principle in the same manner as the D.C. Circuit, i.e., the court must be satisfied that FERC has supported its conclusion that the scope and nature of the benefits to be provided by the transmission warrant recovery of its costs on a broad basis. In *ICC I*, the Seventh Circuit found that FERC had failed to justify system-wide allocation for "backbone" transmission, observing that "[n]othing in the Commission's opinions enables an answer" to the question of whether the proposed cost allocation is justified. *ICC I*, 576 F.3d at 477. In the present case, by contrast, FERC clearly was mindful of the *ICC I* holding and went to considerable lengths to support its conclusion that the MVP category of major new transmission projects would provide regional benefits sufficient to justify regional cost recovery. *See, e.g.*, MVP Order, PP 197, 200, Hoosier App. 453, 455; MVP Rehearing Order, PP 123-24, Hoosier App. 122-25.

4. The Seventh Circuit properly upheld FERC's choice not to assess MVP costs on generators.

The MVP Filing did not change (as relevant here) the tariff's pre-existing rules on the allocation to new generators connecting to the grid of the costs of network transmission upgrades occasioned by such interconnection requests. Petitioners object to this result, and to FERC's rejection of intervenor requests to split MVP costs generically among loads and generators. Hoosier Petition at 16, 23-25; Michigan Petition at 7.

As shown above, MVP treatment is limited to projects that have broad regional benefits. Consequently, their costs are appropriately allocated on a broad basis, and need not also be imposed on individual parties that are somehow deemed to be "more responsible" for the upgrades without regard to their regional benefits. Nor was FERC obliged to include generators among the parties generically assigned MVP costs. FERC previously has found that it need not assign a share of network upgrade costs to generators, and was expressly affirmed on that point by the D.C. Circuit. *See Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007) ("*NARUC*") (rejecting an argument that the cost causation principle requires generators to be assigned responsibility for network upgrade costs, because even if a customer is said to have caused the need for a network upgrade, "the addition represents a *system* expansion used by and benefitting *all* users due to the integrated nature of the grid") (citation omitted) (internal quotation marks omitted).

B. The Alleged "Far-Reaching Implications" of the Seventh Circuit Decision Do Not Warrant This Court's Review

In addition to alleging a split among the circuits, the Hoosier Petitioners also seek to engage this Court's review because of alleged "far-reaching implications" of the Seventh Circuit's decision. Hoosier Petition at 20, 24. This argument seems premised, however, on the Hoosier Petitioners' flawed view that the Seventh

Circuit has dramatically departed from the D.C. Circuit's teachings on the standards that should govern FERC's cost allocation orders. As shown above, that view is incorrect. If anything, adoption of Petitioners' views would have far-reaching adverse implications, and would represent a dramatic turn-around in FERC's efforts to foster development of regional wholesale power markets. For decades, FERC has routinely granted rolled-in pricing, i.e., system-wide cost allocation, for transmission that is integrated with the system that a public utility plans and operates on a single-system basis. *Cf. NARUC*, 475 F.3d at 1285 (relying on FERC's "long-held understanding that Network Upgrades provide system-wide benefits"). Here, where MISO promotes regional efficiency by dispatching generation resources and planning enhancements to facilities on a single-system basis, MISO should not be required to show what no other public utility has ever had to show, i.e., that every proposed new regional transmission enhancement passes a cost-benefit test for each customer before its costs can be allocated to all customers.

The Hoosier Petitioners' related arguments that the Seventh Circuit's decision "tramples" on principles of federalism, Hoosier Petition at 17, 27-28, are similarly unsupported and once again, the Petitioners fail to present a valid reason for the Court to grant the Petition. The MVP Orders focus solely on rates under a single tariff undisputedly subject to FERC's exclusive jurisdiction under the FPA. When FERC acts within its jurisdiction, the fact that its decisions have an effect on non-jurisdictional entities does not affect FERC's jurisdiction. *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481-82 (D.C. Cir. 2009) (finding

FERC's exercise of jurisdiction over the terms of a wholesale capacity market was not an impermissible regulation of generation even though it could affect developer choices of where to locate generation). *NARUC*, 475 F.3d at 1280, 1282-84 (finding that FERC's exercise of its authority to require FERC-jurisdictional utilities to exercise their state law granted eminent domain authority in a non-discriminatory manner did not improperly infringe on or "commandeer[ ]" state authority, as many federal actions permissibly impact state authority); *see also SMUD*, 616 F.3d at 536 (stating that FERC's proper exercise of its authority "was not transformed into a violation of its statutory jurisdiction by dint of its incidental effect" on a non-jurisdictional entity) (citation omitted). The Seventh Circuit's decision, dismissing the claims that the MVP Orders impermissibly intruded on state rights, is therefore perfectly consistent with the decisions of other circuits.

C. Consistent with Court Standards, FERC Did Not Improperly Reject the Calls for an Evidentiary Hearing, and Parties Were Permitted the Opportunity to Challenge the Evidence Relied Upon by FERC.

In its decision, the Seventh Circuit rejected claims that FERC acted improperly in denying requests for hearing and failing to allow parties to take pretrial discovery. *ICC II* at 775-76, Hoosier App. 13-16. Petitioners oppose this finding, claiming that the court's decision creates a circuit conflict on FERC's discretion to hold, or not hold, a trial-type hearing. Michigan Petition at 24; Hoosier Petition at 31-36. Petitioners also complain they were improperly denied the chance to conduct discovery, and assert that because FERC's decision was based on studies relied upon by the MVP Applicants that were not part of the formal record, the Seventh Circuit's decision upholding the FERC findings is infirm. Michigan Petition at 25-26; Hoosier Petition at 31-36.

This is an extreme stretch. The standard of when FERC must order a trial-type hearing is well-settled, does not vary among the circuits, and is highly deferential. Even when there are disputed issues of material fact, FERC need not hold a trial-type hearing if it can resolve the issues based on the written record before it "unless motive, intent, or credibility are at issue or there is a dispute over a past event." *Blumenthal v. FERC*, 613 F.3d 1142, 1145 (D.C. Cir. 2010) (citation and internal quotation marks omitted). A trial-type hearing is not necessary when, as here, all parties were provided with the opportunity to supply evidence and present affidavits. *See Cal. ex rel Lockyer*, 329 F.3d at 713 (FERC provided a hearing and adequate due process when it considered and responded to arguments raised in parties' motions to intervene and rehearing requests); *Cent. Me. Power Co. v. FERC*, 252 F.3d 34, 46-47 (1st Cir. 2001) (upholding procedures when extensive evidentiary submissions were submitted by both sides and stating "[t]he term 'hearing' is notoriously malleable"); *Pac. Gas & Elec. Co.*, 746 F.2d 1383, 1387 (9th Cir. 1984) (formal hearing not necessary when FERC was presented with technical legal analysis from the concerned parties).

FERC also has wide discretion to manage its own proceedings. *See Mich. Pub. Power Agency v. FERC*, 963 F.2d 1574, 1579 (D.C. Cir. 1992) (FERC's decision not to hold a hearing was a "reasonable exercise of its discretion to manage its proceedings"); *Blumenthal*, 613 F.3d at 1144 (FERC's choice to hold an evidentiary hearing is discretionary); *Pac. Gas & Elec.*, 746 F.2d at 1386 (court "must allow the FERC wide discretion in selecting its own procedures" (citation omitted)).

Here, resolving a policy question of how far and wide to allocate costs for a category of major transmission upgrades that meet certain tariff criteria is exactly the type of issue that FERC regularly decides without trial-type procedures. FERC's decision may be informed (as it was here) by affidavits on the competing considerations from utility rate design experts, but cross-examination typically is not needed to allow FERC to assess such experts' rate design policy recommendations. If FERC does not order a trial-type hearing, its rules plainly state that there is no entitlement to discovery. *See* 18 C.F.R. § 385.401(a).

All that remains of Petitioners' arguments on this point, therefore, is their objection that some of the data underlying MISO's cost-benefit analyses was not included in the FERC record. But Petitioners cannot deny that much of that data *was* available to them through other means. The studies relied upon by the MVP Applicants were summarized in the testimony provided by the MVP Applicants. These studies were publicly available, often posted on the internet, or provided to parties as part of the stakeholder process that resulted in the MVP Filing. *See* MISO App. 15-18 (MVP Filing Letter); MVP Order, PP 168 n.211, 210 n.270, Hoosier App. 432-33, 461. While certain workpapers were not produced, FERC was well within its discretion to determine, as it did, that it would be "unduly burdensome" to require MISO to produce such "intermediate analyses," and the remaining evidence provided FERC with a sufficient basis for its decision to approve the MVP Filing.

In addition, as the cases cited by the Hoosier Petitioners make clear, Hoosier Petition at 31-32, the salient questions are whether the evidence has been presented to the parties and whether the parties have had the "suitable opportunity to contradict it or 'parry its effect.'" *See Union Elec. Co. v. FERC*, 890 F.2d 1193, 1202-03 (D.C. Cir. 1989) (observing that section 556(e) of the Administrative Procedure Act, 5 U.S.C. § 556(e), mandates that parties must have a chance to dispute the facts noticed and to parry their effect by offering contrary evidence or analyses); *see also S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 187-88 (D.C. Cir. 2013) (indicating that an agency has the right to take official notice of a material fact, if parties have the opportunity to show to the contrary). Parties here were indeed presented with the evidence and had the chance to parry and refute it through their comments, protests, and additional filings in response to the MVP Filing. In that regard, FERC provided the parties with an extended comment period, and granted waivers of its general prohibition against filing answers. *See Midwest Indep. Transmission Sys. Operator, Inc.*, Errata Notice Extending Comment Period, Docket No. ER10-1791-000 (July 20, 2010) (granting parties an extension of time of more than five weeks to file comments and protest); MVP Order, P 47, Hoosier App. 365 (accepting answers and waiving general prohibition against answers). Parties had the full opportunity to challenge these studies, and did so, through their comments and protests. *See, e.g.*, MVP Order, PP 57-151, Hoosier App. 369-424 (listing parties who filed substantive comments and other pleadings and providing detailed summaries of comments and protests filed in response to MVP proposal); *see also* Protest and Request for Rehearing of MISO Northeast Transmission Customers, Docket No. ER10-1791-000, Affidavit of Andrew C. Dotterweich, ¶¶ 8-13 (Sept. 10, 2010), Michigan Petition Appendix at 84a-91a (affidavit of witness challenging evidence of cost savings presented in the MVP Filing). Any statement that parties were not afforded the chance to challenge or refute the evidence relied upon by the MVP Applicants is simply wrong.

CONCLUSION

As set forth above, the Seventh Circuit's decision is consistent with, and not in conflict with, the decisions of this Court and the other courts of appeal. Accordingly, the Court should deny the Petitions for Writ of Certiorari.

Respectfully submitted,

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APPENDIX

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APPENDIX 1

MidwestISO
Energizing the Heartland

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July 15, 2010

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Midwest Independent Transmission System Operator, Inc. and the Midwest ISO Transmission Owners, Docket No. ER10-1791-000

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Federal Energy Regulatory Commission's ("Commission") regulations, 18 C.F.R. § 35, *et seq.*, and in accordance with the Commission's October 23, 2009 order in

Docket No. ER09-1431-000[1], the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and the Midwest ISO Transmission Owners[2] (collectively "Filing Parties"), respectfully submit for filing an original and five (5) copies of proposed revisions to the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").[3] As detailed below and in the accompanying testimony and Tariff changes, the Filing

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[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060, at P 1 (2009) ("October 23 Order").

[2] For the purposes of this filing the Midwest ISO Transmission Owners are Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, Central Illinois Light Co. d/b/a AmerenCILCO, and Illinois Power Company d/b/a AmerenIP; American Transmission Company LLC; Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Southern Minnesota Municipal Power Agency. Individual Midwest ISO Transmission Owners supportive of this filing may submit supplemental comments in this proceeding regarding, *inter alia*, the impact of the proposed Tariff revisions on their individual systems and customers or issues associated with implementation of the proposed Tariff revisions.

[3] Midwest ISO, FERC Electric Tariff, Fourth Revised Volume No. 1.

Parties propose to: (1) establish a new category of transmission projects designated as Multi Value Projects ("MVPs") and a corresponding cost allocation methodology for such projects; (2) provide for Generator Interconnection Projects ("GIP") arising within a defined time period to share the costs of Network Upgrades on which they mutually rely; and (3) otherwise retain the cost allocation for Network Upgrades[4] needed for GIPs that was conditionally accepted by the Commission in the October 23 Order.

I. INTRODUCTION

The Tariff changes proposed in this filing are part of an ongoing, comprehensive review of the Midwest ISO's Regional Expansion Criteria and Benefits ("RECB") transmission cost allocation methodologies. The proposed changes are the result of more than 19 months of Midwest ISO stakeholder and RECB Task Force discussions, engaging various interest groups responsible for evaluating the Midwest ISO's transmission planning and generator interconnection processes, in close coordination with the Organization of MISO States ("OMS") through its focused Cost Allocation and Regional Planning ("CARP") working group proceedings.

As described in more detail below, the Filing Parties propose to establish a new transmission project planning and cost allocation category, i.e., the MVP, for projects that enable the reliable and economic delivery

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[4] Capitalized terms not otherwise defined in this transmittal letter and the enclosed testimony have the meanings provided in the Tariff.

of energy in support of documented energy policy mandates and address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones. Recognizing the regional orientation of such projects, their costs will be allocated to all load in, and exports from, the Midwest ISO on a postage-stamp basis. Moreover, recognizing the year-round benefits of such projects, their costs will be recovered based on system usage. The new MVP transmission project category, and its associated broad-based cost allocation, are designed to: (1) facilitate the integration of large amounts of location-constrained resources, including renewable generation resources; (2) support Midwest ISO member and customer compliance with evolving state and federal energy policy requirements; (3) enable the Midwest ISO to address multiple reliability needs and provide economic opportunities through regional transmission development; and (4) strike a better balance than the current effective rules in allocating costs among multiple beneficiaries by reserving the GIP category (which allocates nearly all costs to Interconnection Customers) for more locally focused Network Upgrades that are not required for the regional system enhancements that will now be covered by the MVP category.

Moreover, the enclosed Tariff revisions will further narrow the cost burden faced by particular GIPs and resolve “first mover/late comer” issues by requiring subsequent Interconnection Customers that benefit from upgrades funded by earlier Interconnection Customers (termed “Shared Network Upgrades” or “SNUs”) to contribute to the costs of such upgrades.

Consistent with the cost-causation principle that is the touchstone of just and reasonable cost allocation, the enclosed revisions allocate new transmission project costs to those that use and benefit from the new facilities.[5] As shown in detail in this filing, regional loads and exports are reasonably expected to be by far the greatest users of MVPs and will, in addition, derive many other concrete benefits from these projects:

- Economic studies show that MVP-type projects will provide widespread regional benefits, including:
    - substantial reductions in regional congestion costs;
    - reductions in transmission losses, effecting significant, broadly shared cost savings;
    - reductions in the region's installed capacity requirement, thus measurably reducing capacity costs throughout the region;

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[5] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, 131 FERC ¶ 61,253, at P 140 (2010) ("Transmission NOPR"); *see also Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252, at PP 66-67 (2010) ("costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the 'cost causation' principle . . . . The cost causation principle also requires the Commission to ensure that the costs allocated to a beneficiary under a cost allocation method are at least roughly commensurate with the benefits that are expected to accrue to that entity.") ("SPP Order").

- Transmission usage studies show that projects similar to those that are expected to qualify for MVP treatment would be used predominantly by regional loads and to serve exports;

- Broad regional cost-sharing for MVPs (coupled with retention of the current GIP cost allocation for Network Upgrades that do not qualify for MVP treatment) avoids the disproportionate impacts that threatened continued access by Midwest ISO loads, through the Midwest ISO market and Tariff, to prime wind-power development areas;

- More closely tailored cost assignment to prospective new generators (oriented more toward Network Upgrades needed to address local issues, and with shared cost responsibility among GIPs for Shared Network Upgrades) improves the region's ability to attract efficient, and diverse, new generation that enhances regional competition, preserves regional reliability, and fulfills public policy goals; and

- The types of projects expected to qualify for MVP treatment will strengthen and enhance reliability across the integrated transmission system on which all regional load and exports rely.

Similarly, Interconnection Customers clearly will cause, use, and benefit from the costs of the Network Upgrades for which they will be responsible under the Tariff revisions in this filing:

- Interconnection Customers that choose to site their projects in areas of the system that require transmission reinforcement, but that are consciously outside the areas where generator access will be improved by MVPs, will cause and properly should bear nearly all the costs of Network Upgrades needed in these areas to enable their reliable interconnection to the system; and
- GIPs that closely follow (i.e., within the near-term planning horizon) "first-mover" GIPs that required Network Upgrades, properly should bear a fair share (based on determined use) of Shared Network Upgrades that the first-mover funded and that make possible their own interconnection to the system.

Thus, the enclosed revisions ensure that the costs assessed to an entity will be commensurate with the benefits received by that entity.

For all of these reasons, as discussed in detail in this transmittal and the enclosed testimony, the Commission should promptly accept the submitted Tariff revisions as just and reasonable, and afford them the earliest possible effective date, i.e., July 16, 2010.

II. EXISTING MIDWEST ISO COST ALLOCATION METHODOLOGIES

As indicated above, the Filing Parties propose both a new transmission cost allocation methodology relating to MVP projects and certain refinements to the interim GIP Network Upgrade cost allocation methodology to apply such revised methodology on a going-forward basis. Both the existing Baseline Reliability Projects ("BRP") ("RECB I") and Regional Beneficial Projects (renamed Market Efficiency Projects ("MEP") in this filing) ("RECB II") cost allocation methodologies, however, will be retained.[6] Moreover, the costs of certain Network Upgrades will continue to be subject to direct assignment.

1. RECB I (Docket No. ER06-18)

BRPs are Network Upgrades required to ensure that the Midwest ISO transmission system remains in compliance with applicable reliability standards adopted by the national Electric Reliability Organization ("ERO") and by the appropriate Regional Entities.[7] BRPs include projects operating at 100 kV or above that are needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers. Under the Tariff, the costs of BRPs meeting certain criteria are eligible to receive partial regional cost sharing.[8]

RECB I also established cost allocation rules for GIPs, which are New Transmission Access Projects (as defined in Section 1.455 of the Midwest ISO Tariff) that

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[6] In the case of MEP projects, however, the Midwest ISO and its stakeholders agree that such cost allocation methodology will be subject to continued review and evaluation through the stakeholder process.

[7] *See* Midwest ISO Tariff at Original Sheet No. 3437.

[8] BRPs must have a project cost of $5 million or more. In the alternative, the project costs must constitute 5% or more of the Transmission Owner's net plant. *Id.* at Original Sheet No. 3456.

are associated with the interconnection of new, or an increase in generating capacity of existing, generation.[9] As accepted by the Commission in 2006,[10] the Midwest ISO incorporated language into its Tariff requiring the Interconnection Customer to pay the entire cost of Network Upgrades in advance. The Tariff provided that if, at the time the Interconnection Customer achieved commercial operation, the Interconnection Customer demonstrated that the generator was designated as a Network Resource or committed by contract of at least one year to supply capacity or energy to a Network Customer, then 50% of the costs of the Network Upgrades for the GIP would be repaid to the Interconnection Customer. As discussed below, the Commission modified the GIP allocation percentages in the October 23 Order.

2. RECB II (Docket No. ER06-18)

As required by the RECB I Order,[11] in November 2006, the Midwest ISO submitted proposed tariff revisions to incorporate a proposed cost allocation methodology for Regionally Beneficial Projects, which are defined in the Tariff as economic upgrades that meet specific standards, including costing more than $5 million, having a voltage 345 kV or greater, and

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[9] *Id.* at First Revised Sheet No. 3442.

[10] *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,106 ("RECB I Order"), *order on reh'g*, 117 FERC ¶ 61,241 (2006).

[11] RECB I Order at P 90.

meeting defined benefit-to-cost requirements.[12] If the project meets these standards, then 20% of its costs will be allocated to all Transmission Customers on a system-wide basis and 80% will be allocated to specific Transmission Customers on a subregional basis based on a beneficiary analysis.[13]

On March 15, 2007, the Commission conditionally accepted the RECB II proposal; and on rehearing, the Commission further directed the Midwest ISO to make informational reports by August 2008 and August 2009 that analyze "the effectiveness of all of the transmission expansion cost allocation methodologies."[14] In compliance with the Commission's RECB II Rehearing Order,[15] the Midwest ISO filed its August 2008 RECB report on August 29, 2008.[16] In that report, the Midwest ISO advised the Commission that many stakeholders were dissatisfied with the RECB cost allocation rules and recommended a continued review of the unanticipated consequences of those rules, and consideration of a possible solution, through the reformation of the RECB Task Force. The Midwest

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[12] *See* Midwest ISO Tariff at Original Sheet Nos. 3443 – 3451.

[13] *Id.* at Original Sheet Nos. 3475 – 3476.

[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,209 ("RECB II Order"), *order on reh'g*, 120 FERC ¶ 61,080, at P 9 (2007) ("RECB II Rehearing Order").

[15] RECB II Rehearing Order at P 9.

[16] Informational Compliance Filing of the Midwest Independent Transmission System Operator, Inc., Docket No. ER06-18-013 (Aug. 29, 2008) ("August 29 Informational Filing").

ISO indicated that such discussions would be guided by the Commission's policy under Order No. 890 favoring cost allocation rules "generally supported by state authorities and participants across the region."[17]

3. RECB III Phase I (Docket No. ER09-1431-000)

On July 9, 2009 ("July 9 Filing"), the Midwest ISO and certain Midwest ISO Transmission Owners (collectively, the "July 9 Filing Parties") filed with the Commission an interim RECB III Phase I proposal to address certain inequities experienced under the then-effective RECB cost allocation rules. Specifically, the July 9 Filing Parties proposed revisions to the Tariff that: (1) eliminated the Line Outage Distribution Factor ("LODF") allocation of generator interconnection-related network upgrades to load in pricing zones; (2) assigned, to Interconnection Customers, the share of costs then allocated to loads on an LODF basis; and (3) eliminated the requirement that Interconnection Customers show designation as a Midwest ISO Network Resource or a one-year power purchase agreement with a Network Customer to be eligible for cost sharing. The July 9 Filing proposed that Interconnection Customers would be responsible for 100% of the costs of Network Upgrades rated below

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[17] August 29 Informational Filing at 4 (citing *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006-2007 FERC Stats. & Regs. ¶ 31,241 at PP 559-560, *order on reh'g*, Order No. 890-A, 2006-2007 FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009)).

345 kV and 90% of the costs of Network Upgrades rated at 345 kV and above (with the remaining 10% being recovered on a system-wide basis).[18] In addition, the Midwest ISO offered to provide the Commission with quarterly reports on the status of its Phase II stakeholder discussions.

In the October 23 Order, the Commission accepted the Filing Parties Phase I proposal conditioned upon the Filing Parties submittal of superseding Tariff revisions on or before July 15, 2010.[19] In addition, the Commission accepted the Midwest ISO's offer to provide the Commission with reports on the status of the Phase II stakeholder process, requiring informational reports that were submitted on November 20, 2009,[20] February 26, 2010,[21] and May 28, 2010.[22] The instant filing is made pursuant to, and complies with, the Commission's October 23 Order, directing the Midwest ISO to submit Phase II Tariff revisions on or before July 15, 2010.

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[18] Midwest ISO Tariff at First Revised Sheet Nos. 3461 – 3466.

[19] October 23 Order at P 1.

[20] *See* Informational Report of the Midwest Independent Transmission System Operator, Inc., Docket No. ER09-1431-000 (Nov. 20, 2009).

[21] *See* Informational Report of the Midwest Independent Transmission System Operator, Inc., Docket No. ER09-1431-000 (Feb. 26, 2010).

[22] *See* Informational Report of the Midwest Independent Transmission System Operator, Inc., Docket No. ER09-1431-000 (May 28, 2010).

III. STAKEHOLDER PROCESS

Since the Commission's October 23 Order, the Midwest ISO and its stakeholders have engaged in a rigorous process focused on developing a "Phase II" cost allocation methodology to integrate location-constrained resources and include a new category of cost sharing for transmission projects driven primarily by the need to integrate large quantities of remote generation resources.[23] In the three informational reports cited above that were required by the October 23 Order, the Midwest ISO provided comprehensive summaries of the RECB Task Force meetings held from

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[23] As described in the July 9 Filing, the Midwest ISO empowered the RECB Task Force to address, in phases, certain cost allocation issues highlighted in the August 29 Informational Filing . In that report, the Midwest ISO advised the Commission that many stakeholders were dissatisfied with the current rules and that some transmission owners were so concerned about the impact of the allocation rules that they might withdraw from the Midwest ISO. As Phase I, the Task Force was directed to address "near-term solutions" to the GIP cost allocation concerns. July 9 Filing at 7. By contrast, Phase II would "focus more broadly on the integration of large quantities of generation located remotely from load," including "a new category of cost sharing" for transmission projects "driven primarily by the need for integration of large quantities of remote generation resources." *Id.* Thus, Phase II would entail a comprehensive look at transmission upgrade cost allocation in light of possible major "superhighway" transmission projects to facilitate regional or inter-regional movement of large quantities of power from remote areas. *See* RECB Task Force Charter, *available at* http://www.midwestiso.org/publish/Document/20b78d_11ef44fc9c0_-77590a48324a/RECB%20Task%20Force%20Charter%20Final%205_7_09.pdf?action=download&_property=Attachment.

June 2009 to May 2010 that will not be reiterated in this filing.

Following the May 28, 2010 informational filing, the RECB Task Force held meetings on June 10, 2010[24] and June 22, 2010.[25] As described in the informational reports submitted to the Commission, the Midwest ISO and its stakeholders had already evaluated numerous cost allocation alternatives, including: an injection/withdrawal proposal, a highway/byway proposal, a proposal by the supporting Transmission Owners, the OMS CARP proposal, a portfolio proposal, and a proposal to maintain the existing provisions with no modifications. Throughout all of the stakeholder discussions, issues regarding potentially adverse market impacts associated with various cost allocation proposals were analyzed and discussed, as described in the Testimony of Todd Ramey.[26]

At the June 10 meeting, the Midwest ISO provided stakeholders with a straw version of its MVP cost allocation proposal,[27] which generally provided that MVP transmission projects would recover their costs

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[24] Draft Meeting Minutes, *available at* http://www.midwestiso.org/publish/Folder/538398_1259d29a2bd_-7c6e0a48324a?rev=2.

[25] Draft Meeting Minutes, *available at* http://www.midwestiso.org/publish/Folder/538398_1259d29a2bd_-7c6e0a48324a?rev=2.

[26] *See* Ramey Testimony at Tab D.

[27] *See* Midwest ISO MVP Cost Allocation Proposal (dated June 3, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7ca50a48324a/Cost%20Allocation%20Straw%20Proposal%20060310.pdf?action=download&_property=Attachment.

through a system-wide usage rate applied to load and an access rate applied to generators. Under this methodology, 80% of MVP transmission facility costs would be recovered from load and exports and 20% would be recovered from Generators and Imports. In addition, 10% of GIP Network Upgrade costs for projects 345 kV or above would be allocated and recovered system-wide under Schedule 26. The remaining costs would be paid for by the interconnecting Generator.

The Midwest ISO also provided an overview of proposed modifications to the GIP Network Upgrade cost allocation methodology and Drive Out Charges.[28] In its status update, the Midwest ISO explained that it had not decided on the final construction of the MVP proposal.[29] One of the considerations at issue regarding this proposal was the potential impact of MVP project cost allocation on generators, including the potential negative impacts on market prices. Additionally, LECG, LLC ("LECG") presented its evaluation of the

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[28] Overview of Major Design Changes (dated June 10, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7db20a48324a/Item%2004%20-%20Overview%20of%20Major%20Design%20Changes%2006-10-10.pdf?action=download&_property=Attachment.

[29] The Conundrum of Transmission Cost Allocation – or Resolving Middle East Peace (dated June 10, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7d6a0a48324a/Item%2004%20-%20Status%20Update.pdf?action=download&_property=Attachment.

initial proposed MVP methodology,[30] identifying potential impacts of the initial MVP methodology on the short-run economic efficiency of the Midwest ISO economic dispatch, long-run impacts on Generator exit and entry, and potential impacts on Midwest ISO consumers. Finally, the Midwest ISO provided stakeholders with a demonstration on how the various proposed MVP rates would be calculated[31] and settled[32]

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[30] Evaluation of MVP Transmission Cost Allocation Design, Prepared by Scott Harvey and Susan Pope (dated June 9, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7db40a48324a/Item%2003a%20-%20Evaluation%20of%20MVP%20Transmission%20CA%20Design.pdf?action=download&_property=Attachment; *see also* Comments on MVP Transmission Cost Allocation Design, Prepared by Scott Harvey and Susan Pope (dated June 10, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7d800a48324a/Item%2003a%20-%20Comments%20on%20MVP%20Transmission%20Cost%20Alloc_Jun%209.pdf?action=download&_property=Attachment.

[31] Sample Multi-Value Project Rate Calculations (dated June 10, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7d720a48324a/Item%2005d%20-%20MVP%20Rate%20Calculations%2006-10-10.pdf?action=download&_property=Attachment.

[32] MVP Usage Rate and Zonal MVP Usage Rate Settlement (dated June 10, 2010), *available at* http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7d910a48324a/Item%2005e%20-%20MUR%20and%20ZMUR%20Settlement%20Treatment.pdf?action=download&_property=Attachment.

and provided an overview of the proposed Tariff amendments to implement the proposal.[33]

On June 22, 2010, the Midwest ISO presented to the RECB Task Force its final MVP proposal as submitted in this filing.[34] As discussed in greater detail below, based on the Midwest ISO's evaluation of potential market efficiency impacts and related seams issues, and having considered stakeholder comments and LECG's evaluation of the initial version of the MVP approach, the final MVP proposal allocates 100% of MVP transmission costs to load and exports. The Midwest ISO also provided an overview of proposed Tariff revisions, including sample MVP rate calculations under the final MVP proposal,[35] presented Midwest ISO Transmission Expansion ("MTEP")

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[33] MVP Cost Allocation Proposal Tariff Revisions (dated June 10, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7db00a48324a/Item%2005a%20-%20MVP%20Cost%20Allocation%20Tariff%20Revisions-RECBTF-061010.pdf?action=download&_property=Attachment.

[34] Midwest ISO FINAL Cost Allocation Proposal (dated June 22, 2010), *available at* http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7b990a48324a/Item%2002%20Midwest%20ISO%20RECB%20Proposal%20Final%2020100622.pdf?action=download&_property=Attachment.

[35] MVP Cost Allocation Proposal Tariff Revisions (dated June 22, 2010), *available at* http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7b830a48324a/Item%2005b%20MVP%20Cost%20Allocation%20Tariff%20Revisions.pdf?action=download&_property=Attachment.

Appendix A project qualifications,[36] and presented impacts to the generator interconnection queue from the integration of MVPs.[37]

At its May 19, 2010 meeting, the Midwest ISO Advisory Committee considered and took action on three motions relating to alternative RECB cost allocation methodologies that had previously been discussed at the RECB TF meetings. In the first motion, the Advisory Committee considered a Midwest ISO developed proposal, key elements of which included: (i) MVPs with 20% of the cost of the MVPs allocated to Generators through a demand-based charge and 80% allocated to Load through an Energy-based charge; and (ii) the continuation of the existing generator interconnection cost allocation approved by the Commission in the October 23 Order. In the second motion, the Advisory Committee considered a proposed methodology supported by OMS CARP, key elements of which included: (i) an allocation of the cost of "Unique Purpose Projects" ("UPPs") 20% to Generators through a demand-based charge and 80% to Load recovered through an Energy-based charge; and (ii) a "higher of" allocation of Generation interconnection charges.

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[36] Appendix A Inclusion Update (dated June 22, 2010), *available at* http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7bc60a48324a/Item%2006%20Appendix%20A%20Inclusion%20Update.pdf?action=download&_property=Attachment.

[37] MVP's vs. SPA (dated June 2010), *available at* http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7bd00a48324a/Item%2005%20-%20Generator%20Interconnection%20Queue.pdf?action=download&_property=Attachment.

Neither of these motions was adopted. Finally, the Advisory Committee considered a third proposal that was supported by a group of transmission owners (the "Supporting Transmission Owners), key elements of which included: i) an allocation of the cost of the UPPs 100% to Load through a demand-based charge; and (ii) the modification of the existing generator interconnection cost allocation approved by the Commission in the October 23 Order to expand the regional cost sharing of facilities at voltages of 345 kV or higher to 20%. This motion was adopted. The Midwest ISO's MVP proposal is generally consistent with that presented in the motion supported by the Advisory Committee.[38]

The Testimonies of Clair Moeller and Jennifer Curran further describe the history of the stakeholder process, and the interaction between the Midwest ISO process and the parallel processes being conducted by the OMS and related state organizations.[39]

The Filing Parties further note that, as is typical of the products of stakeholder discussions, the revisions proposed herein necessarily result from a balancing of interests and compromises. It is unlikely that any stakeholder believes that every element of this proposal is optimal. However, the Filing Parties strongly believe

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[38] A copy of the minutes from the May 19, 2010 Advisory Committee which were approved at the June 16, 2010 meeting can be found at: http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7e7b0a48324a/AC%20Draft%20Minutes%2020100519.pdf?action=download&_property=Attachment

[39] Moeller Testimony at 3-4, 7-8, 11; Curran Testimony at 14-19.

that the cost allocation methodology which has been produced by this balancing of interests is equitable to all parties and will result in the greatest overall benefits for the Midwest ISO and its customers.

IV. JUSTIFICATION FOR PROPOSED TARIFF REVISIONS

The Commission has recognized that cost allocation reform is one of the most difficult issues facing transmission providers and Regional Transmission Organizations ("RTO") today.[40] Transmission cost allocation challenges are heightened by changing federal and state energy policies and the recognized need for substantial transmission system enhancements to meet increased demand and integrate new generation resources into the grid. The MVP proposal is part of the Midwest ISO and its stakeholders' ongoing efforts to implement a fair Network Upgrade cost allocation methodology that encourages transmission system development to support system reliability and economic goals, renewable resource integration, and other public policy objectives. Accordingly, submission of the MVP and related GIP Network Upgrade cost allocation proposal is a critical addition to the existing RECB I and RECB II cost allocation methodologies, and is a further step in establishing a holistic approach to transmission system planning, generator interconnection, and Network Upgrade cost allocation, consistent with

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[40] *See., e.g.,* Transmission NOPR at P 152 ("cost allocation within RTO or ISO regions, particularly those that encompass several states, is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair.").

Commission and judicial precedent and the goals of the Commission articulated in its Transmission NOPR.

A. Commission Precedent

Under section 205 of the FPA, the Commission is required to ensure that the rates, terms, and conditions for transmission of electricity in interstate commerce are just, reasonable, and not unduly discriminatory or preferential.[41] In applying this mandate, the Commission and the courts have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the cost causation principle, i.e., the requirement that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[42] The Commission and the courts assess compliance with that principle "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[43] Consideration of benefits is relevant because "[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its

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[41] 16 U.S.C. § 824d.

[42] *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992).

[43] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (*citing K N Energy*, 968 F.2d at 1300; *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002); *Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004); *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346-47 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 4-5 (D.C. Cir. 2002); 16 U.S.C. § 824d).

contributions the facilities might not have been built, or might have been delayed.[44]

Under the cost causation principle, the Commission must ensure that the costs allocated to a beneficiary are at least roughly commensurate with the benefits that are expected to accrue to that entity.[45] However, the Commission and the courts have recognized that cost allocation is not an exact science where costs and benefits are allocated with exact precision.[46] The U.S. Supreme Court has stated that "allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[47] Elaborating on this appropriate deference, the court in *Illinois Commerce Commission* explained:

> We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. If it cannot quantify the benefits to the midwestern utilities from the 500 kV lines in the East … but it has an articulable and plausible reason to believe

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[44] *Id.*

[45] *Ill. Commerce Comm'n*, 576 F.3d at 476-77 (citing *Midwest ISO Transmission Owners*, 373 F.3d at 1369); *Sithe*, 285 F.3d at 5.

[46] *See Midwest ISO Transmission Owners*, 373 F.3d at 1368-69 (" [N]ot surprisingly, we have never required a ratemaking agency to allocate costs with exacting precision"); *Sithe*, 285 F.3d at 5 ("FERC is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly").

[47] *Colo. Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945).

> that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.[48]

In Order No. 890, among other reforms intended to clarify and expand the obligations of transmission providers to ensure that Transmission Service is provided on a non-discriminatory basis, the Commission directed each transmission provider to develop a transmission planning process that satisfies nine principles, including a "Cost Allocation for New Projects" principle. Order No. 890 did not impose a particular cost allocation method, but provided overall guidance to permit public utility transmission providers, customers, and other stakeholders to determine methods appropriate for their particular regions that are consistent with the cost causation principle. The Commission stated that when considering a dispute over cost allocation, it would exercise its judgment by weighing several factors, including: (1) whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them; (2) whether a cost allocation proposal provides adequate incentives to construct new transmission; and (3) whether the proposal is generally

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[48] *Ill. Commerce Comm'n*, 576 F.3d at 476-77 (*citing Midwest ISO Transmission Owners*, 373 F.3d at 1369; *Sithe*, 285 F.3d at 5).

supported by state authorities and participants across the region.[49]

As discussed in more detail below and in the Testimony of Clair Moeller and Jennifer Curran, the Tariff revisions proposed in this filing fully comply with Commission and judicial precedent governing cost allocation because they adopt a cost allocation methodology for new transmission projects that distributes the costs of MVPs to customers in a manner at least roughly commensurate with the benefits realized by those customers.[50] As Ms. Curran indicates, the Midwest ISO has identified several categories of benefits of MVPs, including advancing state and federal energy public policies, reductions in production costs and losses, reduced capacity requirements, and increased reliability, that accrue broadly to customers across the Midwest ISO region.[51] The Midwest ISO also has conducted analysis of transmission system usage that indicates predominantly regional usage of transmission facilities that are likely to qualify as MVPs.[52] The MVP proposal further recognizes the integrated nature of the transmission system and accounts for the changing use of the transmission

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[49] Order No. 890 at P 559.

[50] Moeller Testimony at 4; Curran Testimony at 7-8.

[51] Curran Testimony at 22-27.

[52] Curran Testimony at 27-29.

system over time by allocating costs on the basis of system usage.[53]

In addition, the courts and the Commission have consistently found that an integrated transmission network, such as the Midwest ISO's, benefits all users of the network.[54] For example, in *Southern Company Services, Inc.*, the Commission stated:

> Rolled-in pricing is appropriate when the relevant facilities are integrated into the transmission network. This pricing is appropriate because it spreads the cost of network facilities across the entire network; as part of the network, the added facilities benefit all users of the network and thus their costs should be shared among all users of the network.[55]

B. October 23 Order

In the October 23 Order, the Commission accepted the Filing Parties' RECB III Phase I proposal, pending submission of superseding Tariff revisions.[56] The

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[53] Curran Testimony at 9-10.

[54] *See, e.g., Me. Pub. Serv. Co. v. FERC,* 964 F.2d 5, 8-10 (D.C. Cir. 1992); *N. Utils. Serv. Co.*, 60 FERC ¶ 61,012 (1992), *on remand from City of Holyoke Gas and Elec. Dept. v. FERC*, 954 F.2d 740, 742-43 (D.C. Cir. 1992).

[55] *S. Co. Servs., Inc.*, 116 FERC ¶ 61,247, at P 17 (2006) (internal footnotes omitted).

[56] October 23 Order at P 57. In accepting the interim proposal, the Commission recognized the scope of the instant Phase II filing as

Commission stated that: "Given the complexity and the challenge of developing the Phase II cost allocation methodology, we strongly encourage Filing Parties and their stakeholders to dedicate themselves to use of the stakeholder process for evaluation of Phase II reforms to transmission planning and cost allocation to more efficiently plan transmission expansions to interconnect and integrate new generation resources."[57] The Commission indicated that "stakeholders may take a comprehensive approach to evaluating transmission needs by considering what upgrades are needed in light of load growth forecasts, aggregate generation interconnection requests, reliability and economic needs and benefits, and state resource policies."[58]

The Midwest ISO and its stakeholders have fully considered the October 23 Order's directives in developing the MVP and GIP Network Upgrade cost allocation proposals described in this filing. The instant proposal recognizes evolving industry and public policy conditions requiring the development of new paradigms

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follows:

Filing Parties state that the Phase II stakeholder process will focus on the integration of location-constrained resources and will include a new category of cost sharing for transmission projects driven primarily by the need to integrate large quantities of remote generation resources. Filing Parties explain that "Phase II involves a comprehensive look at transmission upgrade cost allocation in light of possible major 'superhighway' transmission projects to facilitate regional or inter-regional movement of large quantities of power from remote areas.

[57] *Id.* at P 70.

[58] *Id.* at P 60.

to facilitate the development of new transmission facilities, including accommodation of renewable energy and other generating facilities that may be locationally constrained, as well as the construction of new transmission facilities to address reliability needs and economic benefits on a regional basis. Moreover, the proposed Tariff revisions recognize that, to facilitate construction of such facilities, a new cost allocation mechanism is necessary to fairly allocate costs to beneficiaries across the entire Midwest ISO region.

C. Transmission NOPR

In the Transmission NOPR, the Commission proposed to amend its Order No. 890 transmission planning and cost allocation requirements to, among other things, "more closely align transmission planning and cost allocation processes"[59] and require each public utility, including RTOs, to consider public policy requirements established by state or federal laws or regulations in the transmission planning process.[60] The Commission indicated that the cost of transmission facilities must be allocated to entities that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits, including benefits such as the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state

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[59] Transmission NOPR at P 156.

[60] *Id.* at PP 63 – 70.

or federal laws or regulations that may drive transmission needs. Moreover, the Commission specifically recognized that a postage-stamp cost allocation appropriately may apply, "where all customers within a specified transmission planning region are found to benefit from the use or availability of a facility or class or group of facilities (e.g., all transmission facilities at 345 kV or higher), especially if the distribution of benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments."[61]

D. Quantification of MVP Benefits

To determine appropriate cost allocation for MVP transmission projects, the Midwest ISO has conducted several analyses to identify the benefits of MVPs to beneficiaries across the Midwest ISO region. The Midwest ISO evaluated and quantified the economic benefits associated with a defined group of transmission projects identified through the Regional Generation Outlet Study ("RGOS") process and other transmission planning studies to meet existing public policy requirements that seem likely to meet the criteria for MVP transmission projects described in more detail below. This group of projects ("MVP starter projects") includes transmission lines in every region of the Midwest ISO footprint and represents about $4.6

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[61] *Id.* at P 167.

billion in investment in the Midwest ISO region, to be developed over the next 10 years.[62]

As Ms. Curran indicates, the Midwest ISO also conducted transmission usage studies on various RGOS projects to determine whether, and the extent to which, those transmission system enhancements would be used on a regional, rather than local, basis.[63] The transmission usage study included over two hundred 345 kV and 765 kV facilities, and evaluated the likely usage of these facilities throughout the year.[64]

In addition to advancing the integration of renewable energy projects necessary to meet defined public policy requirements, the Midwest ISO has determined that the MVP starter projects would alleviate major areas of congestion in the Midwest ISO, which will allow for the more efficient delivery of Energy to load and also results in substantial production cost benefits. Specifically, as demonstrated in the Testimony of John Lawhorn, the Midwest ISO projects that the MVP starter projects developed within the first 5 to 10 years following approval of the proposed MVP cost allocation methodology will generate between $400 million to $1.3 billion in aggregate annual adjusted production cost savings, spread almost evenly across all Midwest ISO Planning Regions.[65]

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[62] Curran Testimony at 22.

[63] Curran Testimony at 28-29.

[64] Curran Testimony at 28.

[65] Curran Testimony at 23-24; Lawhorn Testimony at 12.

In addition to production cost savings, the Midwest ISO estimates development of the MVP starter projects to result in an annual reduction of approximately 2,000,000 MWh in transmission system losses.[66] About $104 million of additional savings are attributable to this reduction in losses. Moreover, reducing system losses also reduces capacity reserves required to maintain reliability, resulting in an estimated $110 million savings from deferred capacity investment.[67]

The reduction in system congestion resulting from construction of the MVP starter projects could also lower the Planning Reserve Margin ("PRM") requirement for the Midwest ISO. Even a relatively small reduction of 0.5% in the PRM would result in the deferral of about 500 MW of capacity investment saving approximately $500 million.[68]

In addition to the projected savings in congestion costs and losses, development of MVP projects will provide regional reliability and other benefits. With respect to reliability, the Testimony of Jennifer Curran explains how an MVP will make the transmission system more resilient to unforeseen contingencies, and thus more reliable for the benefit of customers.[69]

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[66] Curran Testimony at 24; Lawhorn Testimony at 14.

[67] Curran Testimony at 24; Lawhorn Testimony at 14.

[68] Curran Testimony at 25.

[69] Curran Testimony at 27.; *See* SPP Order at P 80 (finding rolled-in pricing to be appropriate because it spreads the cost of network facilities across the entire network, and as part of the network, the added facilities benefit all users of the system)(citing *Southern*

Moreover, as demonstrated in the Testimony of John Lawhorn, development of the MVP starter projects also is expected to reduce wind facility curtailments by approximately 25% in the east region.[70]

The transmission usage studies indicated that the evaluated RGOS projects would be used overwhelmingly (i.e., 80%, mileage-weighted) on a regional basis.[71] As Ms. Curran explains, because almost any transmission improvement project necessarily will be used locally to some extent, the indicated very high level of regional usage "underscores that these types of facilities are essentially for the purpose of strengthening the regional transmission system, for the use and benefit of all market participants that use the regional grid."[72] Ms. Curran concludes that, in light of the high level of regional use of MVP-type projects, and the many other concrete benefits that such projects provide that are broadly shared across the region, allocating the costs of MVPs

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Company Services, 116 FERC ¶ 61,247 (2006)); *See also Midwest ISO Transmission Owners*, 373 F.3d at 1369 ("upgrades designed to 'preserve the grid's reliability' constitute system enhancements [that] are presumed to benefit the entire system.")(citing *Entergy Services Inc. v. FERC*, 319 F.3d 536, at 543 (D.C. Cir. 2003).

[70] Lawhorn Testimony at 13-14.

[71] Curran Testimony at 28-29.

[72] Curran Testimony at 28-29.

to all loads and exports based on their use of the transmission system is just and reasonable.[73]

E. MVP Proposal Consistency With Cost Causation Principles

As discussed above, projects that are likely to qualify as MVPs provide many quantitative and qualitative benefits to customers throughout the Midwest ISO region. The MVP methodology, therefore, is based on the Commission's core cost causation principles summarized above; namely, those that benefit from new transmission facilities should pay the costs of building the facilities. The MVP cost allocation methodology spreads 100% of all Network Upgrade costs to all load and exports on the basis that MVPs and their associated transmission upgrades provide region-wide benefits to the Midwest ISO footprint as a whole.

Additionally, given the integrated nature of the Midwest ISO transmission system, the regional benefits that accrue from MVP Network Upgrades impact all users of the Midwest ISO transmission system in some way.[74] Accordingly, by allocating 100% of Network Upgrade costs to load and exports, the Midwest ISO's MVP cost allocation proposal honors the

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[73] *Id.*; *See also* SPP Order at PP 73-81 (accepting SPP's regional cost allocation methodology on the basis of transmission usage studies that demonstrated less than 100% regional usage coupled with other demonstrated benefits)

[74] *Ill. Commerce Comm'n*, 576 F.3d at 477 ("No doubt there will be *some* benefit to the midwestern utilities just because the network *is* a network.") (emphasis in original).

Commission's long-standing recognition of the integrated nature of transmission systems, the benefits shared across the transmission system as a result, and the preference for spreading the cost of transmission upgrades across the entire region given the integrated nature of the transmission system and benefits shared by all users of the network.[75]

Moreover, the MVP cost allocation proposal has been designed such that the allocation of costs will change over time in a manner that corresponds with the changing nature and classification of the beneficiaries, resulting in costs being allocated under the MVP proposal in a manner at least roughly commensurate with benefits to customers. The studies and analyses described above were performed for purposes of evaluating the likely use of the transmission system at specific points in time and given certain assumptions regarding the types of MVP facilities that may be constructed. However, such individual analyses and assumptions are, by their nature, necessarily somewhat limited and imprecise, when viewed alone. As the Commission has noted, "relying solely on the costs and benefits identified in a quantitative study at a single point in time may not accurately reflect the true beneficiaries of a given transmission facility, particularly because such tests do not consider any of the qualitative (i.e., less tangible) regional benefits inherently provided by an EHV transmission network."[76]

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[75] *See* Section IV.A, *supra*.

[76] SPP Order at P 76.

Consistent with Order No. 890, the MVP proposal provides adequate incentives to construct new transmission. As discussed in the Testimony of Jennifer Curran, the implementation of the MVP proposal will facilitate the development of documented public policy transmission projects in a number of respects. First, the "lumpy" costs of transmission upgrades relating to public policy driven generation projects, which are generally located remotely from load, will now be allocated on a regional basis rather than to the "first movers" of such projects. Such cost allocation will remove barriers to the construction of required transmission because it will spread related transmission costs regionally, consistent with the ultimate beneficiaries of such public policy driven projects, rather than allocating the costs to generators.[77]

In addition, as described in the Testimonies of Jennifer Curran and Eric Laverty, the MVP cost allocation proposal addresses and resolves the unintended consequences of the prior GIP cost allocation methodology in effect before the current proposal accepted by the October 23 Order.[78] The GIP cost allocation continues to eliminate the disproportionate allocation of Network Upgrade costs to pricing zones that would not necessarily benefit from such Network Upgrades under the previously effective LODF methodology because such costs are now allocated on a regional basis. As a result, utilities such as Otter Tail Power Company ("Otter Tail") and

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[77] Curran Testimony at 5-6.

[78] Curran Testimony at 10-12.

Montana-Dakota Utilities ("MDU") will not be allocated a disproportionate share of Network Upgrade costs (as was the case under the LODF methodology) based on application of the proposed MVP cost allocation methodology.[79] Notably, elimination of this disproportionate impact also benefits the region as a whole. By providing an ongoing solution to the serious concerns that prompted Otter Tail and MDU to give notice of withdrawal from the Midwest ISO, the filed proposal helps to retain access, under the Midwest ISO's market and Tariff, to areas of prime wind-power development.

As described in Section III of this transmittal letter, and in the Testimonies of Clair Moeller and Jennifer Curran, the MVP proposal also complies with Order No. 890 given that it was developed through a collaborative process with state authorities and participants across the Midwest ISO region.[80]

In addition, while the Commission has not yet issued a final rule on the Transmission NOPR, the Tariff revisions proposed in this filing comport with the Transmission NOPR proposal specifically to consider state and federal public policy requirements in transmission planning and cost allocation, and to ground transmission cost allocation decisions in the planning process. The proposed MVP methodology's broad allocation of costs to beneficiaries across the Midwest ISO region, and its reliance on MVPs identified through the planning process, place the

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[79] Curran Testimony at 11.

[80] Moeller Testimony at 4, 18; Curran Testimony at 14-19.

Midwest ISO at the forefront of the Commission's evolving transmission planning and cost allocation policy as suggested by the Transmission NOPR.

In sum, the MVP regional cost allocation methodology is consistent with the cost causation principle because it matches regional benefits with regional cost recovery. The MVP proposal therefore is just and reasonable and merits acceptance by the Commission.

V. DETAILED DESCRIPTION OF, AND FURTHER JUSTIFICATION FOR, PROPOSED TARIFF REVISIONS

In order to implement the proposed MVP and GIP Network Upgrade revisions generally described above, the Filing Parties propose to revise several provisions of the Tariff, including Module A, Attachments X and FF, and Schedules 7, 8, 9, and 26. The Filing Parties also propose new Tariff provisions, including a new Attachment MM, and new Schedules 26-A and 26-B. Each of the proposed Tariff revisions is identified in Tab A, and is described generally below.

A. MVP Criteria and Cost Allocation Methodology

As described above, the MVP planning and cost allocation category is designed, among other purposes, to facilitate the interconnection of location-constrained resources (including renewable generation) in the Midwest ISO footprint and to satisfy other existing and potential future public policy requirements by removing cost barriers currently impeding such development.[81] Specifically, the lumpy costs associated with transmission system upgrades relating to public policy driven, and other regionally beneficial, transmission projects will be allocated on a regional basis to load and exports. As shown above, the proposed cost allocation appropriately allocates costs based on the nature of and benefits associated with such projects, rather than to first movers through the generator interconnection process, as is the case today.[82]

1. MVP Criteria And Eligibility

All transmission projects that are approved for inclusion in Appendix A of the MTEP after July 15, 2010 will be carefully scrutinized and evaluated to determine cost sharing eligibility under the MVP cost allocation methodology. As described in the Testimony of Jeffrey Webb, such determination will be made based on the Midwest ISO's Order No. 890 compliant transmission planning process. However, existing transmission facilities, facilities under construction, and facilities approved in Appendix A of prior MTEP reports that have not yet started construction will continue to have their costs allocated under the cost allocation methodology in place at the time of the facility's approval by the Midwest ISO Board of Directors. As discussed above, the MVP cost allocation methodology will not replace the existing transmission facility cost allocation processes relating to BRP and MEP projects.

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[81] Curran Testimony at 3-6.

[82] Curran Testimony at 8-9.

As set forth in Attachment FF, and as described in the Testimony of Jennifer Curran,[83] in order for a transmission project to qualify as an MVP, it must meet at least one of the following three criteria:[84]

- Criterion 1 - The project must be developed through the transmission expansion planning process for the purpose of enabling the transmission system to deliver energy reliably and economically support documented energy policy mandates or laws that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade; and/or
- Criterion 2 - The project must provide multiple types of economic value across multiple pricing zones with a total project benefit-to-cost ratio of 1.0 or higher, as defined in Section II.C.6 of Attachment FF. In conducting the benefit-to-cost analysis, the reduction of production costs and the associated reduction of locational marginal prices ("LMP") resulting from a transmission congestion relief project are not additive and are considered a single type of economic value; and/or

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[83] Curran Testimony at 30-31.

[84] Proposed Midwest ISO Tariff at Original Sheet No. 3451A.

- Criterion 3 - The project must address at least one Transmission Issue associated with a projected violation of a North American Electric Reliability Corporation ("NERC") or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. In this case, the project must generate total financially quantifiable benefits in excess of the total project costs based on financial benefits and project costs, as defined in Section II.C.6 of Attachment FF.

The Testimony of Jennifer Curran further describes how the determination of whether a specific transmission project satisfies one of these three MVP criteria is made.[85] Projects meeting more than one criteria (i.e., resulting in the project being both MVP and BRP eligible) will be considered MVPs.

In addition to meeting at least one of the criteria identified above, MVP eligibility also depends on satisfying the following requirements:[86]

- Facilities associated with the transmission project must not be in service, under construction, or approved for construction by the Midwest ISO Board of Directors prior to July 16, 2010, or the date the constructing entity becomes a Transmission Owner, whichever is later.

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[85] Curran Testimony at 34-38.

[86] Proposed Midwest ISO Tariff at Original Sheet Nos. 3451B-3151C.

- The transmission project must be evaluated through the Midwest ISO's transmission planning process and approved for construction by the Midwest ISO Board of Directors prior to the start of construction, where construction does not include the preliminary site and routine selection activities.
- The transmission project must not contain any transmission facilities listed in Attachment FF-1 of the Midwest ISO Tariff.
- The total capital cost of the transmission project must be greater than or equal to the lesser of $20,000,000.00 or 5% of the constructing Transmission Owner's contemporaneously reported net transmission plant.
- The transmission project must include the construction or improvement of transmission facilities operating at voltages above 100 kV.[87]
- Network Upgrades driven solely by an Interconnection Request or a Transmission Service request will not be considered MVPs.

The Tariff revisions also specify that certain project types cannot qualify for MVP cost allocation:[88]

- Any Network Upgrade cost associated with constructing an underground or underwater

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[87] A transformer is considered to operate above 100 kV when at least two sets of transformer terminals operate at voltages above 100 kV.

[88] Proposed Midwest ISO Tariff at First Revised Sheet No. 3451.

transmission line above and beyond the cost of a feasible alternative overhead transmission line that provides comparable regional benefits; and

- Any direct current ("DC") transmission line and associated terminal equipment when the Midwest ISO is not authorized to schedule or dispatch the DC transmission line, when real-time control of the DC transmission line is not turned over to the Midwest ISO's automatic generation control system, and/or when the DC transmission line is operated in a manner that requires specific users to subscribe for DC Transmission Service.

While an MVP must include some facilities operating above 100 kV, the MVP category does not exclude lower-voltage facilities. Such lower-voltage, or "underbuild," facilities will be included in the MVP category so long as they are, from a planning perspective, required as part of the same project as the MVP.[89] As described in the Testimony of Jennifer Curran, such required facilities could include, for example, the costs to upgrade a 69 kV transmission line determined to experience an overload resulting from construction of a 765 kV transmission facility that qualifies as an MVP.[90] If a transmission project with a Network Upgrade is recommended for construction solely as a result of an interconnection request or a transmission service request, however, such Network

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[89] Curran Testimony at 31.

[90] Curran Testimony at 31.

Upgrade will not qualify as an MVP.[91] On the other hand, a project that otherwise qualifies as an MVP and is recommended for construction by both the generator interconnection planning process and the transmission expansion planning process within the same planning cycle will be classified as an MVP.[92] The Testimony of Jeffrey Webb describes in more detail the transmission planning process, including a discussion of how required underbuild facilities are evaluated as part of a transmission project,[93] and a description of the time in the planning process at which the ultimate MVP determination is made for cost allocation purposes.[94] The Testimony of Eric Laverty describes in more detail the changes to the generator interconnection planning process.

2. Economic Value Determination

As noted above, both Criterion 2 and Criterion 3 MVP transmission projects must demonstrate quantifiable economic benefits, as defined in Section II.C.6 of Attachment FF,[95] and as further described in the Testimony of Jennifer Curran.[96] A Criterion 2 MVP

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[91] Proposed Midwest ISO Tariff at Original Sheet No. 3451C.

[92] Curran Testimony at 33 .

[93] Webb Testimony at 10-11.

[94] Webb Testimony at 11.

[95] Proposed Midwest ISO Tariff at Original Sheet Nos. 3451A-3451B, 3451E.

[96] Curran Testimony at 35-38.

transmission project must provide multiple types of economic value, such as the reduction of planning reserve margins and the reduction of energy and operating reserve costs. In addition, the economic value resulting from such a project must be spread across multiple pricing zones. Economic value is only realized, however, when the economic benefits exceed the associated project's economic costs, and where such value is present in multiple pricing zones, calculated for the first 20 years of a project's life.[97] Ms. Curran explains that the 20-year period used for calculating the benefit-to-cost ratio strikes the right balance between the desire to maximize the long-term value of the transmission system and the desire to manage payback expectations and potential future uncertainties.[98] A project that provides economic value in a localized area only (e.g., a load pocket), may qualify as an MEP under the existing MEP cost allocation methodology, but would not qualify as an MVP.[99]

A Criterion 3 MVP must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones.[100] The process for calculating economic value

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[97] Curran Testimony at 35-38.

[98] Curran Testimony at 36.

[99] Curran Testimony at 32, 37.

[101] Proposed Midwest ISO Tariff at First Revised Sheet No. 3478.

relating to Criterion 3 MVP transmission projects (i.e., application of the benefit-to-cost ratio test) is otherwise the same as described above with respect to Criterion 2 projects.

Determining economic value across multiple pricing zones ensures that Criterion 2 and Criterion 3 MVP transmission projects provide benefits that are regional in nature, and is consistent with the proposed MVP cost allocation methodology. Moreover, analyzing benefits over a twenty-year period recognizes that the beneficiaries of such projects may change over time, which also is consistent with the proposed MVP cost allocation methodology.

3. MVP Cost Allocation

The Tariff revisions proposed in this filing provide recovery for 100% of all Network Upgrade costs from load and exports using a per-MWh charge.[101] The MVP charge will be based on the annual revenue requirements reported by each Midwest ISO Transmission Owner for projects that meet the MVP criteria.[102]

a. *Allocation to Load, Export, and Wheel-Through Transactions*

With respect to export and wheel-through transactions, all external transactions sinking outside the Midwest ISO, including those sinking in PJM, will

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[101] Proposed Midwest ISO Tariff at First Revised Sheet No. 3478.

[102] Proposed Midwest ISO Tariff at First Revised Sheet No. 3779.

be subject to the proposed MVP charge.[103] The MVP charge is properly applied to all such transactions because the MVP transmission infrastructure ultimately will benefit not only load internal to the Midwest ISO, but external loads subject to public policy requirements and thus benefiting from the construction of the MVP facilities.[104] Notably, exports to PJM will bear only the costs of the new regional beneficial transmission facilities classified as MVPs. Consistent with existing Commission directives,[105] rates covering the costs of existing and other types of new facilities under Firm and Non-Firm Point-To-Point Transmission Service reservations for external transactions sinking in PJM will continue to be discounted to zero.

b. *Usage Based Charge*

As noted above, the MVP charge is proposed to be applied on a usage (i.e., MWh) basis rather than a

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[103] Curran Testimony at 14.

[104] Curran Testimony at 14.

[105] The Commission's orders regarding rate pancaking do not preclude the proposed Schedule 26-A surcharge on exports to PJM load that use *new* MVP transmission facilities. Those orders essentially addressed *existing* transmission facilities, and expressly required the development of different rules for allocating "the cost of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO." *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168, at P 60 (2004), *order on reh'g*, 131 FERC ¶ 61,174, at P 22 (2010) (noting requirement to develop "a proposal for allocating to customers in each RTO the cost of new transmission facilities that are built in one RTO but provide benefits in the other RTO").

demand (i.e., MW) basis. As explained in the Testimony of Jennifer Curran, a usage-based charge is warranted because energy flows and the corresponding benefits will occur in all hours of the year, not just during peak demand. This is in contrast to many local facilities in existence today, which were constructed to meet the peak demand of the area in which they are located.[106]

Moreover, as Ms. Curran testifies, Load Serving Entities use the transmission system on a regional basis under the Midwest ISO's security constrained economic dispatch, which frequently results in transactions between Local Balancing Authorities within the Midwest ISO Balancing Authority Area.[107] As detailed above, MVP-related reductions in production costs (*e.g.*, congestion and losses) underscore the usage-based benefits of MVPs. Moreover, the MVP cost allocation proposal does not make an up-front allocation of costs based on an analysis of benefits and usage at a specific point in time, but instead allocates costs based on usage over time, which helps ensure that as usage and benefits change, cost allocation also will change accordingly.[108] All of these factors demonstrate that allocation of the MVP charge on a usage basis is just and reasonable.

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[106] Curran Testimony at 12.

[107] Curran Testimony at 13-14.

[108] Curran Testimony at 9-10.

4. MVP Usage Rate and Transmission Revenue Distribution

The MVP Usage Rate ("MUR") is an energy-based charge used to recover the MVP Annual Revenue Requirements from monthly withdrawals, exports, and wheel-through transactions, as described and calculated in accordance with Attachment MM of the Tariff. Attachment MM includes language to prevent over-recovery of Attachment O revenue with the revenue requirement calculated pursuant to Attachment MM subtracted by each Transmission Owner from their respective Attachment O revenue requirement.[109]

Similar to Schedule 26, which governs the recovery of the costs of Network Upgrades that are determined under Attachment FF to be subject to Attachment GG charges, Schedule 26-A will not be assessed on Grandfathered Agreements.[110]

Schedule 26-A also sets forth the revenue distribution for revenue collected for MVPs. As and to the extent that the Midwest ISO collects revenues from the MUR, it shall remit such revenues to Transmission Owners in proportion to their annual pro-rata share of

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[109] Midwest ISO Tariff, Attachment MM at Original Sheet No. 3780. In a subsequent filing, the Midwest ISO Transmission Owners will file the necessary revisions to Attachment O to prevent this potential over-recovery.

[110] Not all Midwest ISO Transmission Owners agree that Grandfathered Agreements should be exempt from charges under Schedule 26 or Schedule 26-A.

the total MVP revenue requirement as determined under Attachment MM.[111]

5. Other MVP Tariff Issues

As set forth in Attachment FF, and as discussed in the Testimony of Jennifer Curran, new Transmission Owners joining the Midwest ISO after the effective date of the MVP cost allocation proposal will be allocated an MVP usage charge to be phased in over a transition period.[112] Specifically, 25% of the charge will apply in the first full year of membership as a Transmission Owner, 50% of the charge will apply in the second full year of membership, 75% of the charge will apply in the third full year of membership, and 100% of the charge will apply thereafter. A new Transmission Owner will not be responsible for any portion of a BRP, GIP, MEP, or Transmission Delivery Service Project approved prior to their entry into the Midwest ISO.[113] On the other hand, a Transmission Owner that withdraws from the Midwest ISO will remain responsible for all financial obligations incurred under Attachment FF while a member of the Midwest ISO.[114]

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[111] Proposed Midwest ISO Tariff, Schedule 26-A at Original Sheet No. 2199B.

[112] Proposed Midwest ISO Tariff, Attachment FF at First Revised Sheet No. 3840, Original Sheet Nos. 3480A-3480B; *See also* Curran Testimony at 37.

[113] Proposed Midwest ISO Tariff, Attachment FF at First Revised Sheet No. 3840.

[114] *Id.*

In addition to the modifications noted above, the Filing Parties are proposing several corresponding changes to affected Schedules. Currently, Schedules 7 (Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service), 8 (Non-Firm Point-To-Point Transmission Service), and 9 (Network Integration Transmission Service) reflect an adjustment to the zonal rates provided thereunder for charges collected under Schedule 26. The Filing Parties are proposing modifications to Schedules 7, 8, and 9 to reflect an additional adjustment to the rates set forth in those Schedules for charges collected under proposed Schedule 26-A, which governs the collection of the MUR charge calculated under proposed Attachment MM.[115] Similarly, the Filing Parties are proposing to amend Schedule 26 to include charges under proposed Schedule 26-A to the existing language indicating that charges under Schedule 26 are in addition to charges under Schedules 7, 8, and 9.[116]

6. Assessment of Potential Market Impacts

In addition to undertaking several analyses necessary to ensure that the MVP cost allocation methodology is consistent with principles of cost

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[115] *See* Summary of Proposed Tariff Revisions at Tab A (listing proposed revisions by section); Proposed Midwest ISO Tariff at First Revised Sheet Nos. 1849A & 1856A, Second Revised Sheet Nos. 1863B & 1870 (Schedule 7); Third Revised Sheet No. 1876, First Revised Sheet No. 1882A & Second Revised Sheet No. 1889B (Schedule 8); Second Revised Sheet No. 1896 (Schedule 8-Michigan); Second Revised Sheet Nos. 1900 &1907B (Schedule 9).

[116] Proposed Midwest ISO Tariff, Schedule 26 at First Revised Sheet No. 2194.

causation as discussed above, the Midwest ISO assessed the potential market impacts of the MVP cost allocation methodology. The results of that analysis are described in the Testimony of Todd Ramey. As described by Mr. Ramey, the key findings of the market analysis were: (1) charging 100% of MVP costs to load, export, and wheel-through transactions as proposed in the filing will avoid the market distortions and other adverse impacts that might result from imposing such a charge on generators and import transactions; (2) while there could be market distortions associated with the export charge, the Midwest ISO weighed the advantages and disadvantages and determined that charging exports the MVP usage charge proposed in the filing, absent other agreements for cost recovery with neighboring regions, is necessary to (a) avoid providing an undue advantage to external loads that will rely on and use the transmission constructed to support MVPs without any cost responsibility for that benefit and (b) place market participants serving external loads in a comparable position to Midwest ISO loads; (3) imposing the MVP charge on a usage basis to Midwest ISO load will not distort the markets; and (4) there may be a need to modify Financial Transmission Rights ("FTR") and Auction Revenue Rights ("ARR") allocation processes so that the benefits of the MVP transmission as determined through the FTR/ARR process are similarly socialized.[117]

In addition to the market analysis performed by the Midwest ISO staff, the Midwest ISO contracted with LECG to provide a qualitative analysis of the potential

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[117] Ramey Testimony at 2-3, 8.

market efficiency impacts of a number of cost allocation methods under consideration during the stakeholder process ("the "LECG Report").[118] As described by Mr. Ramey, LECG performed market impact analyses of various proposed cost allocation methodologies, including the so-called injection/withdrawal and highway/byway methodologies.[119] In general, the LECG Report supported the Midwest ISO's market analysis and the MVP approach ultimately adopted by the Midwest ISO.[120]

Additionally, the OMS CARP supported the creation of a new category of projects similar to MVPs, but proposed allocating a percentage of the costs of such facilities to new and existing generators in addition to load and exports. Ultimately, the Midwest ISO determined that any cost allocation to generators or to import transactions was not necessary or appropriate.[121] In reaching this decision, the Midwest ISO considered the potential impacts on market efficiency that could result from allocating MVP costs to new and existing generators, including those potential impacts described in the LECG Report.[122] In addition, the Midwest ISO considered whether

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[118] Ramey Testimony at 3.

[119] A link to the LECG Report is included with the Testimony of Todd Ramey. Ramey Testimony at 3, n. 2.

[120] Ramey Testimony at 7.

[121] Ramey Testimony at 4.

[122] Ramey Testimony at 8; LECG Report at 23-39 (discussing potential market impacts).

allocating such costs to new and existing generators would result in seams issues between the Midwest ISO and its neighboring RTOs and/or other utilities (including PJM and Southwest Power Pool, Inc. ("SPP")), none of which impose such costs on generators.[123] Moreover, the Midwest ISO determined that the proposed allocation of GIP Network Upgrade costs, described below and in the Testimony of Eric Laverty, represented an appropriate, just and reasonable allocation of costs to generators.[124]

Finally, as discussed in more detail in the Testimony of Todd Ramey, the Filing Parties propose no changes in this filing to the existing FTR/ARR allocation design. However, the Midwest ISO has established a stakeholder process to examine whether any changes to the FTR/ARR allocation design may be appropriate based on the creation of the new MVP category of transmission projects.[125]

B. GIP Network Upgrades

1. Explanation of GIP Revisions

Once a Network Upgrade is found to be required for a particular GIP, cost allocation for the Network Upgrade remains the same as in the current Tariff language adopted in the July 9 Filing.[126] However, as a

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[123] Ramey Testimony at 2-7.

[124] Laverty Testimony at 18, 27, 34, 36-39.

[125] Ramey Testimony at 8-9.

[126] As noted above, the October 23 Order accepted the current effective rules under which the Interconnection Customer bears

result of the Tariff revisions in this filing: (1) the costs allocated to GIPs as a whole are expected to be reduced relative to the current rules because some Network Upgrades will be allocated as MVPs, rather than as GIP-Network Upgrades; and (2) even if a GIP Network Upgrade is required for an Interconnection Customer, it may be classified as an SNU requiring each Interconnection Customer that depends on that upgrade to share in the costs of the upgrade. The Filing Parties have revisions to Tariff Attachments X and FF to create the SNU category of Network Upgrades.

The enclosed Tariff revisions retain the current cost allocation methodology for GIPs (with the addition of MVPs and SNUs) because the underlying circumstances that prompted the current cost allocation rules have not materially changed. Specifically, significant numbers of generator interconnection requests continue to originate in areas of the Midwest ISO region that lack sufficient transmission infrastructure to accommodate all of the requests. The impact is most pronounced in, but is not limited to, the Otter Tail and MDU zones, as the Commission recognized the RECB III Phase I proposal "reasonably address[es] for the interim period the balance between costs and benefits in the Otter Tail and MDU zones and in other zones."[127] In order for the output from numerous proposed generators in these

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100% of the costs of required Network Upgrades rated below 345 kV and bear 90% of the costs of required Network Upgrades rated at 345 kV and above (with the remaining 10% being recovered on a system-wide basis). *See* October 23 Order at PP 1, 8.

[127] *Id.* at P 49.

wind-rich regions to reach load, significant upgrades to the transmission system will be needed and, absent the current cost allocation methodology, the impact would disproportionately affect certain Transmission Owners.[128] As discussed in the Testimony of Eric Laverty, these circumstances have not changed substantially. For example, there are now 10.2 MW of interconnection requests for every 1 MW of load in the Otter Tail zone (rather than 12.7 MW as noted in the July 9 Filing) and for the MDU zone, the ratio has worsened to 5.3 MW of interconnection requests to 1 MW of load (from a ratio of 4.7 to 1 as noted in the July 9 Filing).[129] Because the current interconnection request-to-load ratios in these two zones remain unacceptably high, retaining the current cost allocation percentages is reasonable to prevent adverse impacts with regard to the balance of costs and benefits, including the possible withdrawal of transmission owning members of the Midwest ISO, as noted in the October 23 Order.[130]

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[128] *Id.* at PP 7-8 (discussing the high percentage of interconnection requests to load in certain areas of the Midwest ISO footprint and the deleterious effects of the prior GIP cost allocation rule that divided Network Upgrade costs equally between the Interconnection Customer and the Transmission Owner).

[129] *See Id.* at P 7; Laverty Testimony at 19-20 (comparing current percentages to those at the time of the July 9 Filing).

[130] *Id.* at PP 6-10 (noting the likelihood that members would withdraw from the Midwest ISO rather than expose customers in their respective zones to dramatically increased costs associated with the earlier-effective cost allocation percentages); *id.* at P 48 (accepting this cost allocation as an "interim approach to the unanticipated consequences resulting from the LODF methodology

The MVP and SNU facility classifications proposed in this filing should mitigate the effect on Interconnection Customers of retaining the current cost allocation rules by reducing the number of facilities that will be subject to the current cost allocation percentages for Network Upgrades. First, Network Upgrades that could be assigned to Interconnection Customers under the current GIP cost allocation may now be designated as MVPs that individual Interconnection Customers would not be required to fund. Second, Network Upgrades that are later found to benefit other "late comer" Interconnection Customers will be designated as SNUs and the Interconnection Customer that originally funded such upgrades would be eligible for contributions from other generators that share the benefit of a specific upgrade.[131]

As discussed in the Testimony of Jeffrey Webb, the MVP designation will be made through the MTEP process,[132] and many long transmission lines needed to integrate large quantities of location-constrained

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due to the concentration of GIPs in pricing zones with low load densities.").

[131] *See* Laverty Testimony at 21-24 (discussing the anticipated effects of MVP and SNU designations).

[132] *See* discussion in Part V.A, *supra; See also* October 23 Order at P 58 (acknowledging that "stakeholders may seek to plan for transmission projects on a region-wide basis to address region-wide concerns as opposed to planning merely for specific generators or load growth.")

resources will likely be designated as MVPs.[133] The cost of such large Network Upgrades might have been assigned to a particular first mover Interconnection Customer prior to the creation of the MVP category, therefore. applying the MVP designation to upgrades that would otherwise be the responsibility of individual Interconnection Customers will result in a substantial reduction in the costs assessed to GIPs, as Mr. Laverty testifies.[134]

As described in the Testimony of Eric Laverty, an SNU is a Network Upgrade or Common Use Upgrade that is funded by an Interconnection Customer(s) and also benefits other, later-identified Interconnection Customer(s).[135] Interconnection Customer(s) that benefit from an SNU will contribute to the reimbursement of the Interconnection Customer that originally funded that SNU. Revisions to Attachment X and Attachment FF of the Midwest ISO Tariff provide mechanisms to facilitate repayment by benefiting Interconnection Customer(s) to the Interconnection Customer(s) that initially funded the SNU from which the subsequent Interconnection

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[133] The Commission has previously recognized that location-constrained resources present unique challenges that other resources do not present and that flexibility in applying the Commission's interconnection policy may be needed to accommodate such resources. *Id.* at P 58.

[134] *See* Laverty Testimony at 21-24 (discussing the anticipated effects of MVP and SNU designations).

[135] *See* Tab A (listing proposed redlined Tariff sheets by section). The proposed revisions to Attachment X include a definition of an SNU.

Customer(s) benefit.[136] To promote certainty among developers and other market participants about possible cost exposure, the Midwest ISO will post information about upgrades eligible for SNU treatment.[137]

Network Upgrades eligible for SNU designation are those GIP Network Upgrades funded by earlier Interconnection Customer(s) ("Generator A"):

i. that have a Generator Interconnection Agreement ("GIA") effective date after July 15, 2010;

ii. that have an actual in-service date that is less than five years from the date of the publication of a System Impact Study that identifies them as being eligible for contribution (i.e., if the subsequent Interconnection Customer's ("Generator B") System Impact Study is published more than five years after the in-service date for Generator A's GIP Network Upgrade, Generator B will not be considered for contribution. The execution date of Generator B's GIA is not relevant to whether Generator B is required to contribute.); and

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[136] Laverty Testimony at 12-13; 29-33. The proposed Tariff revisions are attached at Tab C.

[137] *See* Laverty Testimony at 28. More specifically, the Midwest ISO will maintain a cumulative list of all GIPs that potentially qualify for SNU treatment. Using this data, an Interconnection Customer will be able to evaluate the likelihood of SNU treatment for a GIP Network Upgrade associated with its project.

iii. that have been determined by the Midwest ISO to benefit a later-interconnected Interconnection Customer (i.e., Generator B).[138]

The Midwest ISO will determine SNUs through its interconnection study process by examining the use of the possible SNU by the subsequent Interconnection Customer(s) and the funding Interconnection Customer(s). After applying filtering criteria to determine appropriate impacts, the Midwest ISO will be able to determine if a late comer Interconnection Customer (i.e. Generator B), benefits from an upgrade funded by a first mover Interconnection Customer (i.e., Generator A). If the subsequent Interconnection Customer uses the SNU to a significant level, then the subsequent Interconnection Customer will contribute funds to cover its share of the SNU that was funded by the original funding Interconnection Customer.[139] The amount of the contribution will correlate to the level of use by the contributing Interconnection Customer. Accordingly, it will be possible for several Interconnection Customers to contribute to the funding of a project that creates significant "headroom," or of a facility from which several Interconnection Customers benefit, such as a new substation to which several projects connect. As a simple example, if a first mover Interconnection Customer must fund an entire new substation, subsequent Interconnection Customers that seek to interconnect using the same substation would

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[138] Laverty Testimony at 25.

[139] Laverty Testimony at 16.

be required to contribute to the cost of that substation under the SNU concept.[140]

2. Determination of GIP Network Upgrade Costs and Funding Mechanism

As discussed above, the cost allocation percentages for GIP Network Upgrades do not change under this proposal. GIP Network Upgrade costs will continue to be allocated to generators based on the percentages in the current Tariff. However, the SNU designation will ensure that an Interconnection Customer will only pay its fair share of the cost of a GIP Network Upgrade that benefits and is used by multiple Interconnection Customers. The proposed revisions also do not modify the current interconnection queue, the study process for Interconnection Requests, or the terms and conditions of the standard *pro forma* agreements in the Generator Interconnection Procedures in Attachment X of the Tariff, except those sections relating to cost allocation and cost recovery, as described below.

The initial steps for funding GIP Network Upgrades will not change from the current methodology. The Interconnection Customer will still fund GIP Network Upgrades by paying 100% of the costs to the Transmission Owner in advance, subject to reimbursement under Attachment FF of the Tariff.[141]

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[140] Laverty Testimony at 6-7.

[141] Proposed Midwest ISO Tariff, Attachment FF at Second Revised Sheet No. 3461; *See* October 23 Order at P 5 (noting that International Transmission Company, ITC Midwest LLC, and Michigan Electric Transmission Company (collectively "ITC") and American Transmission Company, LLC ("ATCLLC") use different

The Transmission Owner will repay the appropriate amounts based on the terms of the underlying agreement and the two options noted in Attachment FF of the Tariff.

As explained in the Testimony of Eric Laverty, Transmission Owners that construct upgrades for GIPs may still select one of two repayment options (Option 1 or Option 2) under Section III.A.2.d. of Attachment FF for Interconnection Customer repayment of the cost of Network Upgrades.[142]

Under Option 1, a Transmission Owner repays 100% of the costs of Network Upgrades constructed for a GIP to the Interconnection Customer under repayment terms consistent with the schedules and other terms of Attachment X.[143] The Interconnection Customer then pays a monthly charge based on the Transmission Owner's annual revenue requirement for each eligible GIP Network Upgrade utilizing the methodology prescribed by Attachment FF for repayment Option 1. This "Network Upgrade Charge" is developed through a formula in Attachment GG of

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cost allocation rules). Generators interconnecting to facilities owned by ATCLLC and ITC will receive 100% repayment pursuant to the applicable sections of Attachment FF (for ITC) and Attachment FF-ATCLLC (for ATCLLC).

[142] Laverty Testimony at 28-29 (*citing* Midwest ISO Tariff at First Revised Sheet Nos. 3461-68).

[143] Laverty Testimony at 30.

the Tariff; the charges to be paid are set forth in service agreements filed with the Commission.[144]

Under Option 2, the Transmission Owner(s) constructing the GIP will repay the portion of the cost of Network Upgrades that is eligible for repayment to the Interconnection Customer (i.e., 10% of the cost of required Network Upgrades rated at 345 kV or greater) in advance.

To permit cost sharing for SNUs, the enclosed revisions: (a) require the Transmission Owner to declare its election of Option 1 or 2 within fifteen (15) days of tender of the draft GIA/Facilities Construction Agreement ("FCA")/Multi-Party Facilities Construction Agreement ("MPFCA") by the Midwest ISO (i.e., commencement of negotiations under Section 11.2 of the Generator Interconnection Procedures), and (b) modify the repayment options to address the cost responsibility of later Interconnection Customers for SNUs.[145]

The Transmission Owner must now elect Option 1 or Option 2 earlier in the process because cost sharing

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[144] *See* Midwest ISO Tariff at Second Revised Sheet No. 3464 (providing the Option 1 formula in Attachment FF and referencing Attachment GG); *see id.* at Second Revised Sheet No. 3623. The Attachment GG formula is not being revised in this filing.

[145] Proposed Midwest ISO Tariff at 1st Rev First Revised Sheet Nos. 3093 & 3093A (Attachment X); Second Revised Sheet Nos. 3462 & 3466, Original Sheet Nos. 3466A & 3466B (Attachment FF). The Tariff sheet designations used here reflect additional unrelated revisions to Attachment X that were accepted effective July 28, 2010 in a Letter Order issued on July 13, 2010 in Docket No. ER10-1366.

for SNUs differs depending on the option selected, and advance knowledge of the repayment option will enable Interconnection Customers to evaluate the timing of any possible future repayment for SNUs.[146]

The changes to the repayment options adapt the current options to the possibility of cost contributions from later Interconnection Customers. Option 1 includes a mechanism is included to permit subsequent beneficiary Interconnection Customers to pay a charge to the Transmission Owner for their share of an SNU. Because a Transmission Owner that selects Option 1 repays 100% of the cost to the funding Interconnection Customer and then uses an ongoing charge to recover the cost from the first mover Interconnection Customer over time, this mechanism is necessary to permit late comer Interconnection Customers who benefit to fund their share of the SNU. The proposed revisions to Attachment FF now provide a formula for calculating this payment, and the Transmission Owner would reduce the charge to the first mover Interconnection Customer accordingly and would administer the monthly charge to all parties contributing to an SNU that is being repaid under Option 1.[147]

For Option 2, the Transmission Owner repays the appropriate percentage of Network Upgrade costs funded by the Interconnection Customer in advance, rather than refunding 100% and collecting a charge over time to recover the remaining amount. Therefore,

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[146] Laverty Testimony at 29-30.

[147] Laverty Testimony at 30-31. *See* proposed redline revisions to Attachment FF at Tab C.

payments from beneficiary Interconnection Customers for SNUs will need to be made to the Interconnection Customer that funded the SNU directly rather than the Transmission Owner. Under the proposed revisions, the Midwest ISO, as Transmission Provider, will determine the up-front compensation amount that the benefiting Interconnection Customer shall submit to the Midwest ISO for payment to the first mover Interconnection Customer that funded the upgrade. The benefiting Interconnection Customer will make a one-time payment pursuant to Schedule 26-B.[148] The revisions to Attachment X provide a mechanism for the timing and method of payment by each benefiting Interconnection Customer depending on whether benefiting Interconnection Customers execute their GIAs prior to the in-service date of the SNU.[149] If the benefiting Interconnection Customers execute their GIAs prior to the in-service date of the SNU, they will be required to post an irrevocable letter of credit payable to the Midwest ISO in the amount equal to their actual or estimated contribution to the SNU costs.[150]

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[148] Laverty Testimony at 32. *See* proposed redline revisions to Schedule 26-B at Tab C.

[149] Laverty Testimony at 32-33. *See* proposed redline revisions to Attachment X and Attachment FF at Tab C.

[150] Laverty Testimony at 33.

3. Justification for the Proposed Cost Allocation Methodology Under the Independent Entity Standard

The Commission reviews RTO proposals to modify the procedures for generation interconnection set forth in Order No. 2003 under an "independent entity" standard of review.[151] Under that standard, RTOs like the Midwest ISO "are entitled to more flexibility in proposing variations than are non-independent entities," because they are "less likely than non-independent entities to favor one generator over another."[152] Accordingly, the Filing Parties must show that the changes proposed in this filing "are just and reasonable and not unduly discriminatory, and that they would accomplish the purposes of Order No. 2003."[153]

In addition, the Commission explained in the October 23 Order that "cost allocation for generator interconnection-related network upgrades must strike an appropriate balance between the entity that 'caused'

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[151] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 2001-2005 FERC Stats. & Regs. ¶ 31,146, (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, 2001-2005 FERC Stats. & Regs. ¶ 31,160 (2004) ("Order No. 2003-A"), *order on reh'g*, Order No. 2003-B, 2001-2005 FERC Stats. & Regs. ¶ 31,171 (2004) ("Order No. 2003-B"), *order on reh'g*, Order No. 2003-C, 2001-2005 FERC Stats. & Regs. ¶ 31,190 (2005) ("Order No. 2003-C"), *aff'd sub nom. Nat'l Ass'n of Regulatory Utility Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[152] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,301, at P 14 (2009) ("Phase II Order").

[153] *Id.*

the need for an upgrade (i.e., by deciding to interconnect a new generator) and the larger set of entities that will actually benefit from that upgrade."[154] The instant proposal is just and reasonable and superior to the Order No. 2003 methodology, as well as an improvement upon the RECB III Phase I proposal accepted in the October 23 Order and earlier Midwest ISO GIP cost allocation methods. Specifically, the instant proposal is just and reasonable because it addresses the free rider/late comer issue, appropriately allocates costs among those who cause the need for and benefit from network upgrades, and appropriately shares costs between generation and load, as discussed below.[155]

The proposed revisions also address the concern expressed in the Transmission NOPR regarding the complexity and uncertainty of transmission cost allocation that, "any individual beneficiary of a project has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development."[156] Consequently, transmission

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[154] October 23 Order at P 54 (citation omitted).

[155] *See* Laverty Testimony at 36-39.

[156] Transmission NOPR at P 40. The Commission also noted that few cost allocation structures exist to accommodate transmission facilities that involve multiple transmission planning regions. *Id.* at P 41. The risk of free rider problems is particularly high for projects that affect multiple utilities' transmission systems and is not easily addressed. Relying exclusively on participant funding without respect to other beneficiaries of a transmission facility increases the incentive to defer investment in the hope of being a free rider. On the other hand, if costs are allocated to entities that

investment can result in free rider problems because "customers who do not agree to support a particular project may nonetheless receive substantial benefit from it."[157] The Transmission NOPR also reaffirmed the cost causation principle and explained that "[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built or might have been delayed."[158]

The SNU and MVP cost allocation methodologies are intended to provide for an equitable allocation of charges to generators and load based on use of and benefits derived from the transmission system. By determining the extent to which later Interconnection Customers benefit from the SNU and having them contribute to the first mover Interconnection Customer, the proposed SNU will more fairly link costs and benefits.[159] As explained in the Testimony of Eric

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receive no benefit from a transmission facility, such entities are more likely to oppose inclusion of the facility in a regional transmission plan or impose obstacles that delay or prevent construction of the upgrade. *Id.* at P 153.

[157] *Id.* at P 124. Different regions have addressed the free rider/late comer problem differently. Some regions have assigned transmission rights only to those who financially support a project or have spread the cost of high voltage projects more broadly than the immediate beneficiaries of the project. *Id.* at P 124 n.125.

[158] *Id.* at P 140 (*quoting Ill. Commerce Comm'n*, 576 F.3d at 476 (internal quotation marks omitted)).

[159] *See* SPP Order at PP 62-89 (approving the RTO's cost allocation proposal and discussing the general requirement that costs must

Laverty, upgrades are not custom designed to fit the precise needs for a given interconnection, but use standardized equipment to take advantage of economies of scale.[160] The Commission has recognized a similar principle for upgrades needed to support a cluster of generators studied under the group study methodology used by the Midwest ISO because, where projects are studied as a group, the cost responsibility of an individual project may be greater than if it were studied individually. However, "it is also possible that the use of group studies will result in cost savings for a customer and that the cost responsibility of an individual project may be less than it would have been had the project been studied individually."[161] This situation is especially pronounced when a group of projects seek to interconnect in a wind-rich region that lacks sufficiently robust transmission infrastructure. Because these upgrades can have the lumpy quality that impacts the first mover while creating an upgrade from which other generators later benefit, the SNU will

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be roughly commensurate with benefits). To paraphrase the Seventh Circuit's explanation, to the extent a generator benefits from new Network Upgrades, "it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed." *Ill. Commerce Comm'n v. FERC*, 576 F.3d at 476.

[160] Laverty Testimony at 12-13 (discussing the lumpy nature of transmission upgrades).

[161] *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,165, at P 19 n.26 (2010)(internal quotation marks and parenthetical removed).

require late comers who benefit from the project to help fund the SNUs from which they benefit.

The proposed revisions will also accomplish two goals noted in Order No. 2003 for participant funding by encouraging efficient siting of generation and preventing improper subsidies.[162] The revisions will encourage projects to site generation efficiently by assigning the majority of the costs associated with Network Upgrades to the Interconnection Customer(s) that benefit from them. For example, under the changes proposed in this filing, long 345 kV upgrades may be designated as MVPs; however, if a generator chooses to locate far from MVPs in a part of the Midwest ISO transmission system with less robust transmission infrastructure in place, that Interconnection Customer will bear the full cost responsibility associated with its siting decision. Even in that instance, the proposed revisions would provide an opportunity for cost sharing and an appropriate price signal for such a first mover Interconnection Customer through the SNU. A late comer Interconnection Customer siting nearby and using previously-funded upgrades could reduce the cost of the first mover by contributing to a SNU.[163] In the event that no MVP or SNU designation applied, then the Interconnection Customer would appropriately bear the full cost of upgrades based on its siting decision. A Network Upgrade that is under consideration for inclusion in MTEP Appendix A will also be listed as a

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[162] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,210, at P 19 (2008) (*citing* Order No. 2003 at P 695).

[163] Laverty Testimony at 20-21, 28.

contingency in the Interconnection Customer's GIA until it is accepted. During this time period, the Interconnection Customer will be on notice that it may be responsible for funding the necessary Network Upgrade based upon the results of the System Impact Study and can make business decisions based upon this knowledge. If the upgrade is later moved to Appendix A, the generator will benefit from knowing that its interconnection service will not be contingent on its funding of the Network Upgrade, but rather will be contingent only upon the Network Upgrade actually being in service.[164]

The Common Use Upgrade ("CUU") definition in the current Midwest ISO Tariff provides a mechanism for several known beneficiaries (i.e., Interconnection Customers with interconnection requests concurrently pending in the interconnection queue) to share the costs of these upgrades in advance.[165] The SNU builds on this concept and addresses the same issue when beneficiaries are identified later in time (i.e., the benefiting Interconnection Customers are not identified in the interconnection queue at the time the first mover is assigned responsibility for the SNU). In combination, these revisions will permit each Interconnection Customer to assess the estimated cost associated with its GIP at the time it will be built (including any CUU identified) and the likelihood of potential

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[164] *See* Laverty Testimony at 34-35.

[165] Phase II Order at P 29 (explaining that "[t]he *pro forma* MPFCA is intended to provide a cost-sharing mechanism that places the cost responsibility with identifiable, queued generation that would require the common use upgrade [CUU].")

reimbursement for a SNU if the project funds an upgrade that is later designated as a SNU. For example, a first mover in a wind-rich region would likely be studied in a group study and might contribute to a large upgrade to reach load as part of a CUU. The CUU process would require projects to commit to fund the CUU early in the process and increase certainty for those projects that remain. To the extent that the size of the CUU permits extra headroom due to the lumpiness of the upgrades, the funding Interconnection Customers could assess the likelihood that a late comer Interconnection Customer would propose a project nearby in order to make use of that capacity and later contribute to the CUU as an SNU.[166]

The proposed revisions address the free rider/late comer issue and the concern with the improper subsidization of late comer projects by first movers who create headroom on the system from which late comer Interconnection Customers benefit. In particular, the SNU will minimize the possibility of free riders and should reduce the number of upgrades for which an Interconnection Customer would bear sole responsibility. The Commission expressly noted the free rider/late comer issue when it accepted the

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[166] The Midwest ISO will amend a GIA to remove the funding contingency for a Network Upgrade that is subsequently approved for inclusion in MTEP Appendix A (which includes MTEP projects that are recommended by Midwest ISO staff and approved by the Midwest ISO Board of Directors for implementation by Transmission Owners) within the later of: (1) one year from the execution or unexecuted filing of the GIA; or (2) the date of issuance of the next annual MTEP report. In such a case, the Network Upgrade will be funded pursuant to the appropriate MTEP rules. Laverty Testimony at 33-34.

implementation of the Midwest ISO's MPFCA and the CUU. The MPFCA and the CUU permit multiple Interconnection Customers that will use a CUU to fund such an upgrade jointly to increase the certainty for all identified beneficiary projects that the CUU will actually be built.[167] In accepting the CUU, the Commission noted that allocating Network Upgrade costs among multiple Interconnection Customers through an MPFCA "simply implements existing tariff language" that permits the determination of cost responsibility for projects in a group study to be determined by factors other than queue position.[168] The SNU concept is analogous.

The SNU also responds, in a manner that is consistent with Order No. 2003 principles, to the concern that a later identified beneficiary of an upgrade would avoid the cost of construction. The SNU approach retains the importance of queue position while denying a windfall to late comer projects at the expense of first movers. This concept is in line with the Commission precedent that addresses first movers who move ahead with funding upgrades before a higher queued project. In such situations, the higher queued, but later-starting Interconnection Customer will repay the lower queued first mover for upgrades that would have been the responsibility of the higher queued

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[167] *See* Phase II Order at P 33 (accepting the CUU proposal and noting the ongoing discussion on the issue of headroom created by upgrades and the potential windfall for late comer projects).

[168] *Id.* at P 32 (*citing* Midwest ISO Tariff at Second Revised Sheet No. 3073).

project.[169] Accordingly, requiring late comer Interconnection Customers to pay their share of Network Upgrades used to support the interconnection requests, even if they were previously funded by another project, is consistent with Order No. 2003 principles.[170] By requiring future beneficiary Interconnection Customers to contribute to the upgrades that they use, SNUs provide for an appropriate cost sharing to refine further the cost sharing provided by the CUU to the ongoing concern with fair treatment of additional headroom on the system created by upgrades and how to allocate that benefit to a future generator that uses such an upgrade.[171]

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[169] *See, e.g.,* Order No. 2003-A at P 318 (*citing Va. Elec. and Power Company*, 104 FERC ¶ 61,249 (2003)) (noting that "[i]f another Interconnection Customer is ready to proceed with its project, it should be allowed to use the capacity that has been earmarked for a higher queued Interconnection Customer that has suspended its project. The Network Upgrades can be built when the latter customer is ready to proceed.").

[170] *Id.* at P 320 (noting that an Interconnection Customer is responsible for "funding the cost of [among other facilities] all Network Upgrades (other than those already in the Transmission Provider's current expansion plan) that must be constructed to support that Interconnection Customer's In-Service Date[.]"). The SNU applies these principles to combat the incentive for projects to delay funding in hopes of benefiting as a free rider by applying cost sharing to late comer projects. *See* Transmission NOPR at PP 40-41, 124 (discussing free rider concerns for transmission upgrades).

[171] Transmission NOPR at PP 40-41, 124; *see* Phase II Order at P 33.

As described above, SNU cost-sharing is time-limited; future GIPs may be assigned a cost of earlier Network Upgrades so long as the publication date of the final System Impact Study for each of those additional future beneficiary Interconnection Customers is no more than five years after the actual in-service date of the Network Upgrade.[172] The five-year period is a reasonable time limitation that is comparable to the near-term planning horizon described by the Testimony of Jeffrey Webb, which is the planning horizon that takes into account generation additions that can be reasonably anticipated.[173]

For all of these reasons, the GIP cost allocation proposal is just and reasonable and consistent with the Commission's direction that "cost allocation for generator interconnection-related network upgrades must strike an appropriate balance between the entity that 'caused' the need for an upgrade (i.e., by deciding to interconnect a new generator) and the larger set of entities that will actually benefit from that upgrade."[174]

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[172] Laverty Testimony at 25.

[173] Webb Testimony at 7 (discussing the short term (one- to five-year) planning horizon); *see also* Laverty Testimony at 26 (noting that the five-year period is comparable to the five-year planning horizon used in the MTEP).

[174] October 23 Order at P 54 (citation omitted).

VI. PROPOSED EFFECTIVE DATE AND REQUEST FOR EXTENDED COMMENT PERIOD

The Filing Parties respectfully request that the proposed Tariff revisions become effective on July 16, 2010, one day following the date of this filing. As explained in the Testimony of Clair Moeller, such an effective date is necessary and appropriate in order to provide guidance and certainty in connection with pending public policy driven transmission project proposals and with respect to the generator interconnection process. The July 16, 2010 effective date was selected to allow transmission projects that may be approved in Appendix A of the 2010 MTEP for MVP cost allocation methodology if applicable.[175] This effective date allows the Midwest ISO to apply the MVP criteria to those transmission projects eligible for approval in the 2010 MTEP and report the projects that are eligible for the MVP cost allocation methodology to the Midwest ISO Board of Directors for approval in December 2010.[176] Moreover, given the Commission's directive to adopt subsequent Tariff revisions by July 15, 2010 to address issues identified in the October 23 Order, stakeholders have been on notice that changes in the Midwest ISO cost allocation methodology were forthcoming and have had ample opportunity to participate in the process, as described above and in the Testimony of Jennifer Curran.

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[175] Moeller Testimony at 20.

[176] Moeller Testimony at 20.

If the July 16, 2010 effective date is not accepted, projects that are being considered in the 2010 MTEP that may qualify as MVPs would not be eligible for MVP cost allocation. This could result in delays in the construction of new transmission infrastructure, the termination of certain projects, delays in realizing incremental regional benefits, and impediments to the Midwest ISO's ability to foster transmission infrastructure to meet documented energy public policies.[177] Also, delaying the effective date would create uncertainty for Interconnection Customers deciding how to proceed with interconnection requests involving significant Network Upgrades that might qualify as MVPs under the new methodology. This uncertainty will drive existing Interconnection Customers to try to time when to move to the next phase of the generator interconnection process. It may even result in Interconnection Customers exiting and re-entering the generation interconnection queue, which could have a cascading adverse impact on lower-queued generation interconnection requests. Accordingly, the Midwest ISO respectfully requests that the Commission waive the 60-day notice requirement set forth in section 205 of the FPA, 16 U.S.C. § 824d, and section 35.3(a) of the Commission's regulations, 18 C.F.R. § 35.3(a), and make the Tariff revisions proposed herein effective as of July 16, 2010, for good cause shown.[178]

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[177] Moeller Testimony at 21.

[178] *See* S. Cal. Edison Co., 132 FERC ¶ 61,007 (2010) (waiving the 60-day notice requirement for good cause shown) (*citing Cent. Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, at 61,338-339, *order on reh'g*, 61 FERC ¶ 61,089 (1992); *see also Allegheny Power*, 131

In addition, the Filing Parties respectfully request that the Commission provide an extended period for parties to file comments on this filing until September 10, 2010. Given the complexity and extent of the proposed Tariff changes, the Filing Parties believe an extended comment period is appropriate to permit all interested parties adequate opportunity to analyze and submit comments on the proposed Tariff changes. In this regard, the Filing Parties note that the proposed extended comment period should better align with the OMS processes, and provide the OMS and its members the opportunity to discuss and comment on the filing.

The Filing Parties further respectfully request that the Commission act on this filing during or prior to its December 16, 2010 meeting. Action by this date will help to provide certainty with regard to complex issues presented herein to the Midwest ISO and its stakeholders.

VII. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to, and the parties request the Secretary to include on the official service list, the

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FERC ¶ 61,278, at P 32 (2010) ("Pursuant to 18 C.F.R. § 35.11, the Commission may waive the 60-day prior notice requirement for good cause shown."); *Central Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, at 61,339 (noting that when considering a waiver request, the Commission "must balance the requirement that utilities promptly file their rates as embodied in the Federal Power Act and the need of utilities to transact business on short notice. Accordingly, we will grant waiver of notice if good cause is shown and the agreement is filed prior to the commencement of service.").

following persons, who shall also be authorized to receive notice in this docket:

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VIII. SUMMARY OF PROPOSED TARIFF CHANGES

In addition to the description of Tariff changes provided above, a summary description of the complete set of changes to existing Tariff provisions, and proposed new Tariff provisions, is attached hereto as Tab A.[179]

IX. SUPPORTING DOCUMENTS

In addition to this Transmittal Letter, the following documents are being submitted with this filing:

Tab A – Summary of Proposed Tariff Revisions

Tab B – Clean Tariff Sheets

Tab C – Redlined Tariff Sheets

Tab D – Ramey Testimony

Tab E – Moeller Testimony

Tab F – Lawhorn Testimony

Tab G – Curran Testimony

Tab H – Laverty Testimony

Tab I – Webb Testimony

Tab J – List of Starter Projects

Tab K – Midwestern Governors Association Letter

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[179] The Commission recently accepted certain revisions to Attachment X in Docket No. ER10-1366-000, with an effective date of July 28, 2010. Due to the order issued in that proceeding, the Midwest ISO is submitting two versions of the revisions to Attachment X; the first set of revisions is redlined against the currently effective Tariff and reflects an effective date of July 16, 2010 on all sheets, the second set (separated by a divider reflecting that the sheets contain recently approved language), contain revisions accepted in Docket No. ER10-1366-000, with the applicable sheets reflecting effective dates of July 28, 2010 (Sheet Nos. 3093, 3093A, 3244 and 3245).

X. ADDITIONAL INFORMATION REQUIRED BY COMMISSION REGULATIONS

While the Midwest ISO submits the instant filing under Part 35 of the Commission's regulations, the Midwest ISO's proposal is not procedurally subject to the requirements set forth in 18 C.F.R § 35.13(a) given that the MVP proposal is a cost allocation filing and not a rate increase filing.[180] As determined by the Commission in the SPP Highway/Byway Order, cost allocation proposals are not subject to the filing requirements for rate increases as outlined in section 35.13(a)(2). Rather, the Commission views such filings "as having been made under the narrow requirements of section 35.13(a)(2)(iii), which pertain to tariff changes other than rate increases."[181]

The Commission's regulations in section 35.13(a)(2)(iii) require that companies file general information in section 35.13(b)[182] and information relating to the effect of the rate change in section 35.13(c).[183] The instant filing includes all the

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[180] *See* SPP Order at P 108.

[181] *Id.*

[182] The general information required under section 35.13(b) includes a list of documents submitted, the effective date, list of recipients of the filing, brief description of the filing, statement of the reasons for the filing, a showing of requisite agreement to the filing, and a statement that there were no illegal, duplicative, or unnecessary costs that are the result of discriminatory employment practices.

[183] Specifically, the information relating to the effect of the rate change includes a comparison of revenues from services under the

information required under section 35.13(b) as applicable. In particular, sections 35.13(b)(6)[184] and 35.13(b)(7)[185] do not apply to this filing. Otherwise, the instant transmittal letter adequately provides a description of and the reasons for the Midwest ISO filing. Additionally, this transmittal letter provides a list of documents submitted with the filing, a proposed effective date, and a statement of service to all Midwest ISO stakeholders.

XI. NOTICE AND SERVICE

The Midwest ISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers, Midwest ISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the Midwest ISO Advisory Committee participants, as well as all state commissions within the Midwest ISO Region. In addition, the filing has been posted electronically on

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rate schedule before the rate change and after the rate change, a comparison of the rate change and the utility's other rates for similar transmission services and an appropriate map showing any specifically assignable facilities that will be installed or modified in order to provide service.

[184] Section 35.13(b)(6) requires a showing that all requisite agreements to the rate change have been obtained. The proposed revisions to the Midwest ISO Tariff do not require any such agreements.

[185] Section 35.13(b)(7) requires a statement showing any expenses or costs included in cost of service statements that have been alleged or judged to be illegal, duplicative or unnecessary costs that are demonstrably the product of discriminatory employment practices.

the Midwest ISO's website at www.midwestmarket.org under the heading "Filings to FERC" for other interested parties in this matter.

XII. CONCLUSION

Wherefore, for all the reasons stated above, the Filing Parties respectfully requests that the proposed Tariff revisions be approved as set forth herein, effective July 16, 2010.

Respectfully submitted,

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APPENDIX 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. ER10-___-___

[Filed July 15, 2010]

Midwest Independent Transmission)
System Operator, Inc.)
)

PREPARED DIRECT TESTIMONY OF
JOHN LAWHORN

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF
JOHN LAWHORN
FILED ON BEHALF OF THE
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP TO THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MIDWEST ISO").

A. My name is John Lawhorn. My business address is 1125 Energy Park Drive, St. Paul, Minnesota 55108. I am employed by the Midwest ISO.

Q. WHAT IS YOUR POSITION, AND WHAT ARE YOUR RESPONSIBILITIES, WITH THE MIDWEST ISO?

A. I am the Director of Regulatory and Economic Studies. I have held this position since May 2006. I am responsible for directing the development and execution of economic transmission planning studies using production cost models, loss of load expectation models and capacity expansion models and analyses for the Midwest ISO transmission planning process. I am responsible for leading strategic assessments that analyze the impact from state and federal regulatory policy initiatives, such as renewable portfolio standard ("RPS") and carbon legislation, on the Midwest ISO and its stakeholders. In addition, I have led large inter-regional studies such as the Joint Coordinated System Plan ("JCSP") and the Midwest ISO's participation in the U.S. Department of Energy ("DOE") sponsored Eastern Wind Integration Transmission Study ("EWITS"), both of which used large scale production cost and capacity expansion models and analyses. Previously, I served in multiple positions within the planning function including Manager of Economic Studies and Models and Manager of Expansion Planning.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Engineering in Energy and Power Systems and a Master of Science in Nuclear Engineering from the University of New Mexico. I am a registered Professional Engineer in the state of New Mexico. Prior to joining the Midwest ISO in October 2002, I was a Director with Navigant Consulting, Vice President with Stone & Webster Management Consultants, Lead Consultant with Energy Management Associates and Supervisor of Fossil and Alternate Fuel with the Public Service Company of New Mexico.

Q. WHAT IS THE PURPOSE AND SUMMARY OF YOUR TESTIMONY?

A. The purpose of this testimony is to describe the models and analytical methods used to quantify some of the economic benefits of Multi Value Projects ("MVP"), in particular the set of MVP "starter" projects representing about 4.6 billion dollars in transmission investment.

MIDWEST ISO PRODUCTION COST SIMULATIONS

Q. WHAT WAS DONE TO DETERMINE POTENTIAL MVP BENEFITS?

A. To determine potential economic benefits of transmission projects and portfolios the Midwest ISO utilizes a production cost model. Production cost model simulations were performed with and without the MVP "starter projects" described in the Testimony of Jennifer Curran. The difference between these two cases shows quantifiable benefits associated with the MVP starter projects such as production cost savings, load cost savings, decreased wind generator curtailment, and reduced system line losses. Potential benefits were calculated for forecast years 2015, 2020, and 2025 under five different public policy/economic scenarios.

PRODUCTION COST MODEL INTRODUCTION

Q. WHAT IS A PRODUCTION COST MODEL?

A. Originally developed in the 1970s to manage and budget fuel inventories, a production cost model's original purpose was to capture all the costs of operating a fleet of generators. While the basic purpose has remained unchanged, production cost models have expanded in both function and complexity to simulate electrical markets. Production cost models use an hourly chronological generator commitment and dispatch algorithm that minimizes costs while simultaneously adhering to a wide variety of operating constraints, also called a security constrained unit commitment and economic dispatch ("SCUC&ED"), to calculate hourly production costs and locational marginal prices ("LMP").

The algorithms used by the production cost model to calculate LMPs and dispatch generation mimic those used in the Midwest ISO market. Production cost models simulate a market on a forecast basis, but models are regularly tested against actual historical market data to ensure that production cost models are an accurate representation of the market.

While load or power flow models are the basis for most transmission reliability and operational planning, production cost models are best used for transmission planning and market analysis. Production cost models allow the simulation of all hours over a year, rather than the single peak (or off-peak) hour as performed with a power flow model. This annual approach provides the Midwest ISO detailed information, such as LMPs, line flows, and congestion across a full range of operating conditions for 8,760 hours. The full year simulation is also significant in that it allows the focus on an annual or energy basis rather than a single point in time, which may not necessarily be indicative of economic effects. In a production cost model the economic impacts of decisions can be simultaneously evaluated for all control areas and markets.

Q. HOW DOES A PRODUCTION COST MODEL WORK?

A. Production cost models require detailed generation data, hourly demand profiles, and a full transmission representation as input. Before a SCUC&ED can be performed, to forecast out-year hourly generation availability, production cost models first creates a generator outage schedule using a random sampling simulation. While these outage schedules are random, the supplied outage criteria and program logic allow them to stay true to historical patterns. Once an outage schedule is built, an automatic maintenance schedule is generated by the program. When the program schedules the maintenance, it will make sure that the one day in ten years loss of load expectation reliability criterion is not violated. Nuclear units use a plant specific fixed maintenance schedule based on their operating cycles. Once the generator outage and maintenance schedules are built, they are fixed so that all simulations done with a case have consistent generator availability.

To perform a SCUC&ED a series of constraints must be provided to the model. While all generator dispatch constraints such as maximum and minimum capacity and minimum up and down times are considered, the number of transmission constraints that can be modeled is limited by computational memory. To most effectively model the transmission system, approximately 1,500 of the most severe limiters of the transmission system, or flowgates, are monitored in an "event file." Event files are reviewed regularly by the Midwest ISO Transmission Owners.

With a representative event file, generation outage library, demand forecast, and precise system inputs a production cost model's SCUC&ED can accurately forecast out-year market economics. To determine potential benefits of a project, a case including the project is compared against the exact same case less the transmission project, also called a base case. Quantifiable differences or potential benefits can be provided across a variety of metrics at a control area level of granularity.

MODEL INPUTS

Q. WHAT DATA INPUTS ARE REQUIRED FOR A PRODUCTION COST MODEL TO SIMULATE THE MARKET ACCURATELY?

A. In order to perform a full SCUC&ED, production cost models require detailed generation, fuel, demand and energy, transmission, and system configuration data. The Midwest ISO makes every effort to corroborate multiple data sources to provide accurate inputs; whenever practical inputs are reviewed through appropriate stakeholder working groups.

Q. PLEASE DESCRIBE THE GENERATION INPUT.

A. To model a generation fleet accurately, resource capacities, fuels, locations, heat rates, ramp rates, operating costs, and operating status must be inputted for all generating units in the study footprint. The Midwest ISO models the majority of the Eastern Interconnection and, approximately 6,200 units are included in the analysis footprint. The Midwest ISO uses the PowerBase database from Ventyx as its platform for generator information for existing units. Although Ventyx corroborates its generator data across sources, the Midwest ISO updates the information based on information provided by Midwest ISO asset owners through a variety of forums. Generators in the Midwest ISO generator interconnection queue with a signed interconnection agreement and an in-service date prior to the study date are also included. Finally, forecast units are added to the model to ensure that out-year planning reserve requirements are met. These forecast units are added using a least cost capacity expansion methodology through an open stakeholder process.

Q. HOW DOES INTERMITTENT GENERATION AFFECT THE GENERATION INPUT?

A. Certain intermittent resources, including wind generation, present unique modeling issues. Variability and uncertainty are the two attributes of wind generation that cause most of the concern related to power system operations and reliability. Wind energy output varies from hour to hour. Because wind generation is driven by the same physical phenomena that controls the weather, the uncertainty associated with the prediction of wind generation level at some future hour, even the next hour, is significant. In production cost models wind generation is not a dispatchable resource. To most accurately model the variability and geographic diversity each wind unit is given a fixed profile based on the year 2005 site-specific historical data collected by the National Renewable Energy Laboratory ("NREL").

Q. PLEASE DESCRIBE THE FUEL INPUT.

A. The initial fuel price forecasts used in the production cost models are sourced from PowerBase. PowerBase maintains a forecast for four types of fuel: coal, uranium, gas, and oil. Base forecasts for coal and oil are based on future contracts. A consistent uranium price is used throughout the study footprint and is based on a future index. Gas units utilize the NYMEX futures price as a monthly profile. The gas base point and growth rate is scenario specific and determined by Midwest ISO stakeholder and regulatory groups.

Q. PLEASE DESCRIBE THE DEMAND AND ENERGY INPUT.

A. To perform a market simulation, production cost models require an hourly demand profile on a control area granularity. Base year peak demand forecasts for the Midwest ISO are provided by Midwest ISO load serving entities for resource adequacy purposes. The demand forecast for control areas outside the Midwest ISO is sourced from FERC Form 714 filings through the PowerBase data. Base year demand levels are scaled by scenario specific growth rates to forecast out year peak demand. An hourly profile from year 2005, which is representative of a typical year, is scaled by the forecasted peak demand and energy levels to form hourly demand inputs for each control area. The 2005 hourly profile is correlated with the hourly wind data profiles from NREL discussed above.

Q. PLEASE DESCRIBE THE TRANSMISSION INPUT.

A. Production cost models require a full transmission topology as input. Transmission topology is sourced from the 2010 Midwest ISO Transmission Expansion Plan (MTEP) power flow models for years 2015 and 2020. These models are based off of the North American Electric Reliability Corporation ("NERC") year 2009 series models and contain a Midwest ISO Transmission Owner updated Midwest ISO insert. Because there are no significant transmission topology changes between years 2020 and 2025, the 2025 production cost models utilize the same transmission topology as year 2020.

Q. PLEASE DESCRIBE THE SYSTEM CONFIGURATION INPUT.

A. System configuration refers to how pools and control areas are defined. A pool is a set of control areas in which all generators are dispatched together to meet load, which is generally representative of an energy market. Hurdle rates are defined between pools to allow energy exchange between pools, but also to simulate inefficiencies between markets. The hurdle rate will influence the capability of a pool to obtain support or sell energy to other pools. If two pools want to exchange energy, the difference in dispatch costs between the buying pool and selling pool must be greater than the hurdle rate between them.

Q. WHAT IS THE MIDWEST ISO PRODUCTION COST MODEL STUDY FOOTPRINT?

A. The power flow case used in the production cost model includes the entire Eastern Interconnection; however, because of a limitation in the model, Florida, ISO New England, and Hydro Quebec have been excluded from the study footprint. Although, these regions have a minimal effect on the Midwest ISO market, fixed transactions are modeled to capture the influence of these exterior areas to the rest of the study footprint.

Q. HOW DO PRODUCTION COST MODELS ACCOUNT FOR OUT-YEAR PUBLIC POLICY AND ECONOMIC UNCERTAINTY?

A. To account for different possible future economic conditions or public policy decisions, such as a federal RPS or carbon emission regulations, the Midwest ISO uses multiple scenarios or futures. These futures utilize a wide range of assumptions around demand growth levels, inflation rates, fuel costs, wind penetrations, and carbon regulations. The intent is to develop "book end" results rather than a single value. Currently, the Midwest ISO uses five futures developed through state regulatory and stakeholder groups: (1) Organization of MISO States ("OMS") Cost Allocation and Regional Planning ("CARP") Business as Usual ("BAU") Future; (2) the CARP RPS Future; (3) the CARP RPS, Carbon Cap, Smart Grid, and Electric Vehicle Future; (4) the Planning Advisory Committee BAU with Mid-Low Demand Future; and (5) the PAC Carbon Cap and Nuclear Generation Future.

Q. PLEASE DESCRIBE THE CARP BAU FUTURE.

A. Developed through the OMS CARP to simulate a status quo environment with a quick recovery from the economic downturn in demand and energy projections. This future models the power system as it exists today with reference values and trends, with the exception of demand and energy growth rates, based on pre-recession historical data. This future also assumes that existing standards for resource adequacy, renewable mandates, and environmental legislation remain unchanged. RPS requirements are met with various renewable resource types as defined for each state by the OMS.

Q. PLEASE DESCRIBE THE CARP RPS FUTURE.

A. This future was developed by the OMS CARP to simulate a federal 20% RPS requirement — whereby 20% of the energy consumption in the Eastern Interconnect is supplied by renewable resources by 2025. New wind generation is forced incrementally into the model yearly starting in year 2012, accounting for the two year regulatory and construction lead time. Capacity factors for wind generators vary regionally from 35% - 45% and are sourced from the NREL dataset. Solar generation is modeled with a 10% annual capacity factor. Hydro and biomass units are modeled with 50% annual capacity factors. As in the CARP BAU future, existing RPS requirements are met with various renewable resource types as defined for each state by the OMS; however, additional renewable energy to satisfy the 20% renewable energy requirement is met solely with wind. Only onshore wind site locations are utilized.

Q. PLEASE DESCRIBE THE CARP RPS, CARBON CAP, SMART GRID, AND ELECTRIC VEHICLE FUTURE.

A. The OMS CARP developed this future to simulate potential public policy outcome. This future includes the 20% federal RPS from the CARP RPS future, with the addition of a carbon emissions cap mandate, smart grid, and widespread electric vehicle use. The carbon cap is modeled after the American Clean Energy and Security Act of 2009 pending before the United States Senate (also known as the "Waxman-Markey" bill or H.R. 2454), which has an 83% reduction of CO2 emissions from a year 2005 baseline by the year 2050. That target is achieved through a linear reduction from 2010 to 2050 with midpoint goals of 3% reduction in 2012, 17% reduction in 2020, and 42% reduction in 2030. To meet carbon emissions limits this future deploys uneconomic coal retirements; oldest and highest heat-rate coal units are retired first. The installation of a smart grid is modeled within the demand growth rate. It is assumed that an increased penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled within the energy growth rate and are assumed to increase off peak energy usage and as such increase the overall energy growth rate.

Q. PLEASE DESCRIBE THE PLANNING ADVISORY COMMITTEE BAU WITH MID-LOW DEMAND FUTURE.

A. This future was developed through the Midwest ISO's stakeholder-based PAC to simulate a status quo future where the economic downturn continues. This future uses the same assumptions as the CARP BAU future, with the exception of employing a lower demand, energy, and inflation rate.

Q. PLEASE DESCRIBE THE PAC CARBON CAP AND NUCLEAR GENERATION FUTURE.

A. Developed through the PAC, this future employs the carbon cap from the CARP RPS, Carbon Cap, Smart Grid, and Electric Vehicle Future, but assumes RPS requirements remain the same. In this future it is assumed that Integrated Gasification Combined Cycle ("IGCC") and combined cycle with sequestration technologies will not develop during the study period and therefore much of the out-year thermal generation is nuclear.

Q. WHAT DO THESE FIVE FUTURES PROVIDE THE MIDWEST ISO?

A. These five futures provide the Midwest ISO a multi-dimensional forecast. While it's unlikely that one of these futures will exactly match economic conditions ten to twenty years into the future, there is a high degree of confidence that the future will be within the bounds of these scenarios. Utilizing multiple futures allows the Midwest ISO to find projects that are not only beneficial under one possible future scenario but sufficiently robust to be beneficial across multiple outcomes.

BENEFITS OF MVP STARTER PROJECTS TRANSMISSION

Q. WHAT METRICS WERE USED TO QUANTIFY BENEFITS ASSOCIATED WITH THE MVP STARTER PROJECTS?

A. The Midwest ISO focused on four quantifiable benefit metrics from the production cost model: production cost savings, load cost savings, wind curtailment improvements, and system line loss savings.

Q. WHAT POTENTIAL ADJUSTED PRODUCTION COST SAVINGS ARE ASSOCIATED WITH THE MVP STARTER PROJECTS?

A. Adjusted production cost is the combined cost of fuel, emission, variable operations and maintenance required for a generation fleet to produce energy adjusted for pool imports cost and exports revenue. The MVP starter projects relieve many of the highest areas of congestion in the Midwest ISO. As transmission congestion is relieved, there is greater access to less expensive generation and thus adjusted production cost decreases. The Midwest ISO annual potential adjusted production cost savings from the MVP starter projects ranged from $297 million to $423 million in year 2015 and $402 million to $1.3 billion in year 2025 under the five future scenarios. Each Midwest ISO Planning Region has positive adjusted production cost savings potential under nearly all scenarios. The distribution of savings is generally evenly divided through the regions with slightly more savings in the Midwest ISO East Planning Region.

Q. WHAT POTENTIAL LOAD COST SAVINGS ARE ASSOCIATED WITH THE MVP STARTER PROJECTS?

A. Load cost is the cost that load serving entities pay to have their load served; it is the MW of load multiplied by the load-weighted LMP. In a congested system LMPs are usually highest in areas of high resource deficiency. As congestion is relieved, the LMPs equalize across a pool allowing most loads to pay a decreased cost. Midwest ISO annual load cost savings potential associated with the MVP starter projects ranged from $14 million to $984 million in year 2015 and -$19 million to 2 billion in year 2025 under the five future scenarios.

A negative load cost savings is the result of neighboring pools having access to less expensive generation that was previously unavailable due to transmission constraints. As outside pools access less expensive generation their load costs decrease; however, the load costs for the source pool increase.

Q. HOW DO THE MVP STARTER PROJECTS HELP TO MEET RPS REQUIREMENTS AND RENEWABLE ENRGY GOALS?

A. Wind generation penetration levels are set to meet RPS with limited overbuilding. If there is inadequate transmission to move the wind energy to demand centers, shift excess energy throughout the transmission system, or outlet power to the transmission system the wind generator will be curtailed. As curtailment rates increase the potential not to meet RPS energy requirements also increase. Production cost models are programmed to allow wind generation to operate even in uneconomic conditions, down to -40 $/MWh LMPs (accounting for the production tax credit that wind units can receive); however, large percentages of curtailment are still present in base simulations. Without the MVP starter projects, the Midwest ISO wind resources annually curtail 7.7% to 30.4% of their total energy; when the MVP starter projects are added, the Midwest ISO's annual wind curtailment rates decrease to 1.5% to 25.3%. A 25% reduction in curtailments in the Midwest ISO East Planning Region is further exemplified as a result of the MVP starter projects.

Q. HOW DO THE MVP PROJECTS IMPROVE SYSTEM LOSSES?

A. To study transmission line loss benefits of MVP projects a separate limited scope study was performed. This study used the CARP BAU future and simulated adding the MVP starter projects in year 2015 and expanding to the Regional Generation Outlet Study ("RGOS") 765kV overlay in year 2025 as described in the Testimony of Jennifer Curran. The MVP starter projects decrease the year 2015 annual Midwest ISO system line losses by 1,503 GWh — decreasing system losses from 3.09% of annual energy to 2.82%. The annual reduction in system line losses from the MVP starter projects results in an annual savings of $68 million. The RGOS 765kV overlay allows the year 2025 annual Midwest ISO system line losses to decrease by 1,975 GWh — an annual savings of $104 million. This annual savings associated with decreased transmission losses is in addition to the aforementioned adjusted production cost and load cost savings.

Q. DOES REDUCING TRANSMISSION LOSSES PROVIDE OTHER BENEFITS?

A. Yes, improving transmission losses can also reduce the capacity reserves required to maintain system reliability. On peak in 2015, the MVP starter projects reduced system losses by approximately 100 MW. Assuming $960,000.00 per MW/year as a typical cost of new entry and a 15% reserve requirement, a 100 MW reduction in losses would result in $110 million of savings in deferred capacity investment.

Q. ARE THERE ADDITIONAL BENEFITS TO THE MVP STARTER PROJECTS?

A. Yes, this testimony focuses on quantifiable benefits measured from production cost models. The MVP starter projects also increase system reliability, improve operating conditions, and ease the burden of generator interconnection costs as described in the Testimonies of Jennifer Curran and Eric Laverty.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT

County of Ramsey)
)
State of Minnesota)

John Lawhorn, being duly sworn, deposes and states: that he prepared the Prepared Direct Testimony of John Lawhorn and the statements contained therein are true and correct to the best of his knowledge and belief.

John Lawhorn

John Lawhorn

SUBSCRIBED AND SWORN BEFORE ME, this 13 day of July, 2010.

KATHERINE A WIESNER
Notary Public
Minnesota
My Commission Expires January 31, 2015

Katherine A. Wiesner

Notary Public
My Commission Expires: 1/31/2015

APPENDIX 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. ER10-___-000

[Filed July 15, 2010]

Midwest Independent Transmission)
System Operator, Inc.)
)

PREPARED DIRECT TESTIMONY
OF
JENNIFER CURRAN

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF JENNIFER CURRAN FILED ON BEHALF OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP TO THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MIDWEST ISO").

A. My name is Jennifer Curran. I am employed by the Midwest ISO, with business address at 720 City Center Drive, Carmel, Indiana, 46032.

Q. WHAT IS YOUR POSITION, AND WHAT ARE YOUR RESPONSIBILITIES, WITH THE MIDWEST ISO?

A. Currently I am the Executive Director of Transmission Infrastructure Strategy, a position that I have held since October 2009. From February 2007 to October 2009 I was Director of Transmission Infrastructure Strategy. I am responsible for directing the development and execution of strategies to enable increased transmission infrastructure investment through the Midwest ISO transmission planning process. In this role, I focus on supporting the state and federal regulatory and business case requirements for transmission infrastructure. In addition, I am responsible for leading the development of effective transmission cost allocation methodologies. I serve as the Midwest ISO staff liaison to the stakeholder committee charged with improvement of the current cost allocation method, the Regional Expansion Criteria and Benefits Task Force ("RECB TF"). I also serve as the Midwest ISO staff liaison to the Planning Advisory Committee, which is the stakeholder committee that provides advice to the Midwest ISO Planning Staff on policy matters related to the process, integrity, and fairness of the

Midwest ISO-wide transmission expansion plan and cost allocation. Previously, I served as the Director of Performance Assurance at the Midwest ISO, responsible for business and financial planning for the Operations areas of the company.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science in Mechanical Engineering from Rice University, and a Master of Business Administration from Duke University. Prior to joining the Midwest ISO in July 2004, I was Manager of Power Generation & Supply Strategy for the Mid-Atlantic and Mid-Continent Regions at Reliant Resources, now RRI Energies.

Q. WHAT IS THE PURPOSE AND SUMMARY OF YOUR TESTIMONY?

A. My testimony will describe the proposed cost allocation solution developed in response to a directive by the Commission in Docket No. ER09-1431-000 to file superseding tariff revisions regarding the Phase II cost allocation methodology on or before July 15, 2010 to address the integration of large quantities of generation located remote from load, and to consider additional improvements to the generator interconnection cost allocation methodology. I will describe how the cost allocation solution will support expansion of the Transmission System to enable documented public policy requirements and/or provide regional economic value achieved through a new type of transmission expansion project referred to as the MVP ("MVP"). My testimony will also outline the guiding principles and stakeholder process used to arrive at the proposed cost allocation solution. My testimony is organized into sections related to the cost allocation solution overview and guiding principles, stakeholder process, description of MVPs, benefits of MVPs, MVP rate design, and other issues.

SOLUTION OVERVIEW AND GUIDING PRINCIPLES

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROPOSED MVP REGIONAL TRANSMISSION COST ALLOCATION PROPOSAL?

A. The MVP regional transmission cost allocation proposal creates a new class of transmission expansion projects and the associated rate design to recover the revenue requirements on a Midwest ISO system-wide basis. This new class of regional transmission expansion projects is referred to as MVPs. MVPs are Network Upgrades that provide regional benefits in response to documented public policy (such as renewable energy standards) and/or by providing multiple regional benefits (such as reliability and/or economic value) to Transmission Customers on a regional basis. I will describe in more detail how MVPs are defined and identified through the planning process later in my testimony.

Q. HOW ARE THE REVENUE REQUIREMENTS ASSOCIATED WITH MVPS RECOVERED?

A. The annual revenue requirements attributable to MVPs will be recovered through an MVP usage rate ("MUR"). The MUR is proposed as a Midwest ISO system-wide rate charged to all energy withdrawn from the Transmission System, including energy withdrawn by loads internal to the Midwest ISO (Monthly Net Actual Energy Withdrawals), energy withdrawn by scheduled export transactions, and energy withdrawn by scheduled wheel-through transactions (Through Schedules). The MUR is a monthly rate assessed upon the actual metered (or scheduled in the case of external transactions) energy withdrawn in a month. I will discuss the MUR in more detail later in my testimony.

Q. DOES THE MVP COST ALLOCATION PROPOSAL REPLACE THE GENERATOR INTERCONNECTION PROJECT COST ALLOCATION METHOD CURRENTLY IN THE TARIFF?

A. No. To the extent that a Generator Interconnection Project requires Network Upgrades above and beyond those associated with an MVP in order to reliably interconnect to the Transmission System the costs of those Network Upgrades will be recovered using the same methodology that was conditionally approved by the Commission on October 23, 2010.

Although we are proposing to retain the current cost allocation for Generator Interconnection Projects, many large-scale transmission upgrades that would, under the current rules, be categorized as Generator Interconnection Project Network Upgrades, will under the proposed rules likely be categorized as MVPs, and their costs allocated to loads rather than to Interconnection Customers Eric Laverty shows, in his testimony, that this impact could be quite substantial

Q. WHAT KEY PRINCIPLES GUIDED THE DEVELOPMENT OF THE PROPOSED COST ALLOCATION SOLUTION?

A. A number of principles guided the Midwest ISO and stakeholders throughout the evaluation of cost allocation solutions and ultimately the development of the MVP cost allocation method as the recommended solution. First and foremost, the Midwest ISO and its stakeholders sought to find a cost allocation solution that would i) enable investment in the regional transmission infrastructure necessary to ensure a reliable and robust transmission system that supports the objectives of public policy requirements while maximizing stakeholder value in the long-run, and ii) allocate the costs of such investment in a fair manner at least roughly commensurate with benefits realized by stakeholders over the long-run. In addition, the Midwest ISO and stakeholders sought to address, to the extent feasible, the free rider and first mover/late comer issues, the changing use of the system over time, cost allocation issues regarding regional versus local use of the Transmission System, and the ability of the transmission system to facilitate both the energy and capacity needs of the region. Additional goals of the process included ensuring that unintended consequences, including but not limited to those associated with the generation interconnection cost allocation method in place prior to July 9, 2009, did not arise.

Q. DO YOU BELIEVE THAT THE MVP COST ALLOCATION PROPOSAL WILL ENABLE REGIONAL TRANSMISSION EXPANSION IN A WAY THAT SUPPORTS PUBLIC POLICY REQUIREMENTS?

A. Yes. First, the MVP cost allocation proposal will greatly facilitate the development of renewable generation required to satisfy documented public policy requirements by removing potential cost barriers to integrating larger amounts of generation, much of which may be located remote from load. Under the current rules, most of the costs of "lumpy" transmission upgrades (as defined and explained by Eric Laverty) that enable compliance with public policy requirements are allocated to generators that seek to interconnect to the system. Under the rules in effect before July 9, 2009, most of those costs would be allocated to the interconnecting generators and the loads that happen to be located in the zones where the upgrades are installed. Both of those approaches embody a local perspective, allocating most costs only to the interconnecting generators or to local loads. Neither of those approaches recognizes the fundamental regional orientation of the major upgrades needed to the Midwest ISO Transmission System in the coming years to enable compliance with public policy requirements and meet other regional objectives. The MVP cost allocation proposal, by contrast, brings a much-needed regional perspective to projects that are inherently regional. The MVP approach encourages the development of regional transmission infrastructure by using an appropriate regional cost allocation methodology that recognizes the regional character and regional benefits of MVPs and, thus, will allocate the costs of regional projects commensurate with their benefits.

Q. DOES THE MVP COST ALLOCATION PROPOSAL ENABLE REGIONAL TRANSMISSION EXPANSION TO SUPPORT INITIATIVES OTHER THAN PUBLIC POLICY REQUIREMENTS?

A. Yes. The MVP cost allocation proposal also allows for the regional expansion of the Transmission System to provide added economic value to Transmission Customers on a regional basis. That is, the MVP cost allocation proposal enables the development of regional transmission infrastructure that provides regional economic benefits in excess of the costs for the regional transmission infrastructure. I discuss specific regional benefits enabled by the MVP cost allocation proposal later in my testimony.

Q. DO YOU BELIEVE THAT THE PROPOSED COST ALLOCATION SOLUTION ALLOCATES COSTS ROUGHLY COMMENSURATE WITH BENEFITS?

A. Absolutely. By definition, MVPs are projects designed to address regional needs, in terms of satisfying regional public policy requirements, providing regional economic benefits, or meeting regional reliability needs. Notably, the regional economic criterion requires a benefit to cost ratio of 1.0 or greater, and the benefits assessed under that criterion, e.g., production cost savings, transmission loss reductions, and maintaining or reducing capacity reserve margins, are broadly shared throughout the region. While, theoretically, a project could qualify as an MVP based solely on its regional public policy benefits, as a practical matter, most MVPs very likely will provide all three types of regional benefits, including a high level of regional economic benefits. This is abundantly clear from a benefits analysis of various "starter" projects, discussed later in my testimony, which include many of the types of transmission enhancements likely to be considered for MVP status in the coming years. While largely developed from a set of facilities designed to meet RPS requirements on a Midwest ISO-wide basis, these projects also appear to offer significant economic benefits. Moreover, even if a project does not pass a 1.0 multiple economic benefit test, it cannot become an MVP unless it satisfies regional policy requirements or ensures regional reliability. Therefore, recognizing the inherent regional orientation of MVPs, their costs are properly recovered on a regional basis, commensurate with their regional benefits, consistent with Commission policy and judicial precedent.

Q. WILL MVPS BE IDENTIFIED BASED ON REGIONAL INPUT?

A. Yes; the regional input process is well underway, as I discuss later in my testimony, drawing on a consensus already achieved among regional policy makers on such issues as the identification of wind-power zones and the optimal approaches to transmission expansion to meet regional public policy objectives. Furthermore, throughout the planning process, as described in the testimony of Jeffrey Webb, all stakeholders have the opportunity to provide input.

Indeed, maintaining regional policy consensus and ensuring all stakeholders have the opportunity to provide input into the identification and validation of MVPs are essential. Policies and other assumptions will change, and the maintenance of continued consensus in the face of these changes is critical to designing and building an effective transmission system. These facts underscore the regional basis of MVPs and that their costs are properly recovered on a broad regional basis.

Q. WHAT IS THE FIRST MOVER/LATE COMER ISSUE AND TO WHAT DEGREE DOES THE MVP COST ALLOCATION PROPOSAL ADDRESS FIRST MOVER/LATE COMER CONCERNS?

A. The firstmover/late-comer issue arises when an individual interconnecting generator or a small group of such generators cause the need for a significant transmission Network Upgrades and consequently, under the current rules, are allocated nearly all the costs of that upgrade. Others that may rely on or benefit from that upgrade are not directly allocated much of its costs. As Eric Laverty shows in his testimony, this can and has raised an impediment to proceeding with generation interconnections. The more substantial the required upgrades, the greater that impediment becomes. Major upgrades that are needed to meet regional objectives could form a major impediment, as well as raise equity concerns about the allocation of such regionally required costs to the few generators that happen to be the first-movers.

The MVP proposal greatly mitigates this concern for the significant amounts of generation expected to be added in support of documented public policy requirements such as the various state renewable portfolio standards ("RPS"), since the costs of those upgrades will be broadly allocated to all loads and exports, rather than almost all to the first-mover generators. First mover Interconnection Customers still will be allocated most of the costs of Network Upgrades that do not qualify as MVPs, but since the MVP category is expected to encompass major upgrades, this would leave the Interconnection Customer responsible only for the more locally focused upgrades needed for its reliable interconnection to the grid. Even there, however, this filing further resolves first mover concerns by assigning cost responsibility for Shared Network Upgrades funded by the first-mover Interconnection Customer to "later-comer" Interconnection Customers that also use and benefit from those upgrades. Eric Laverty provides extensive support in his testimony for this aspect of the filed proposal.

Q. DOES THE MVP COST ALLOCATION PROPOSAL TAKE INTO ACCOUNT CHANGING BENEFITS AND USAGE OF THE TRANSMISSION SYSTEM OVER TIME?

A. Yes. The MVP cost allocation proposal does not make an upfront allocation of costs based on an analysis of benefits and usage at a specific point in time, but instead allocates costs based on usage over time. Therefore, as the entities that use and benefit from MVPs change over time, the MVP cost allocation method properly assigns the appropriate level of costs to those users. Also, because the rate mechanism is an energy-based usage charge rather than a demand charge, the MVP cost allocation method accurately captures the benefits of MVPs as they accrue throughout the year based on usage.

Q. **TO WHAT DEGREE DOES THE MVP COST ALLOCATION PROPOSAL ADDRESS THE FREE RIDER ISSUE?**

A. The "free rider" issue occurs when loads or export transactions benefit from specific transmission expansion, but do not share in the cost of that transmission expansion. In the MVP cost allocation proposal, the free rider issue is addressed because all entities withdrawing energy from the Midwest ISO Transmission System share in the cost of MVP projects and because, as shown in this filing, the proposal recognizes, and allocates costs on the basis of, the many broad regional benefits provided by MVPs.

Q. TO WHAT DEGREE DOES THE MVP COST ALLOCATION PROPOSAL ADDRESS THE UNINTENDED CONSEQUENCES DEALT WITH IN THE COST ALLOCATION APPROVED BY THE COMMISSION IN ITS OCTOBER 23, 2009 ORDER?

A. The MVP cost allocation proposal fully addresses the problem with unintended consequences that resulted from the prior Generator Interconnection Project cost allocation method. The MVP criteria are intended to provide for the development of regional transmission expansion projects that address regional drivers and are thus allocated on a region-wide basis, rather than to a few pricing zones. Under the Generator Interconnection Project cost allocation methodology effective prior to July 9, 2009, 50% of the cost of Network Upgrades were allocated to the constructing Transmission Owners, and then subject to cost sharing based on the Line Outage Distribution Factor ("LODF") methodology. The LODF methodology tends to allocate significant costs to the host zone and in the vicinity of the Network Upgrade (which is appropriate for Baseline Reliability Projects). This tendency, coupled with the high number of Network Upgrades driven by future public policy driven generation interconnection requests in the vicinity of the Otter Tail Power Company ("Otter Tail Power") and Montana-Dakota Utilities service territories, resulted in the potential allocation of significant costs to Otter Tail Power and Montana-Dakota Utilities that were appreciably disproportionate to the benefits of those Network Upgrades to those entities.

The MVP proposal alleviates this issue because most of the transmission infrastructure needed to provide regional public policy benefits will be developed as MVPs through the transmission expansion planning process, with costs allocated regionally. Only those Network Upgrade costs associated with any remaining transmission infrastructure and resulting from the generation interconnection process will be allocated to the interconnecting generators (with such costs being allocated either 100% for facilities at voltage classes below 345 kV, or 90% to the interconnecting generators and 10% on a regional basis for Network Upgrades that operate at voltages classes of 345 kV or above). Under the MVP proposal, situations like the potential significant cost allocation impacts to Otter Tail Power and Montana-Dakota Utilities described above will be eliminated.

Moreover, by alleviating these disproportionate impacts, the MVP proposal also helps ensure that transmission zones encompassing prime wind-power development potential will remain part of the Midwest ISO's market and Tariff, thus allowing continued access to those areas by all Midwest ISO grid users.

Q. WHY IS THE MVP CHARGE BASED ON ENERGY INSTEAD OF DEMAND?

A. In considering the primary objectives of regional transmission infrastructure to enable public policy requirements and to provide regional economic benefits within the Midwest ISO market, it became apparent that a significant portion of the benefits associated with MVPs would occur at times other than the peak demand. That is, while many of the local transmission facilities already in existence today were constructed to meet the peak demand of the area in which they are located, regional facilities tend to be utilized throughout the year with a focus on energy delivery across the footprint during periods in addition to the peak demand. For example, if wind generation is used to help meet the energy requirements of RPSs, only a small percentage of the energy generated by wind will occur during periods of peak demand, *i.e.*, the small percentage of hours that drive demand-type charges. Furthermore, it is expected that a significant portion of the economic value associated with MVPs will be the reduction of production costs, an energy based measure, during the year. For these reasons, a usage charge was selected as the preferred method for the recovery of costs of MVPs.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW REGIONAL TRANSMISSION FACILITIES TEND TO BE UTILIZED THROUGH THE YEAR RATHER THAN DURING THE PEAK DEMAND?

A. The Midwest ISO energy and operating markets were designed to ensure that the cost of energy and operating reserves are minimized at all times based on current offers and system constraints. This is accomplished by frequently redispatching generation, demand response, and dispatchable external transactions to achieve new operating points that minimize costs based on continuous changes in system demand, loop flows, fixed external transactions, and the operational status of resources and transmission elements. In the day-ahead markets, the system is redispatched each hour, so there are 8,760 day-ahead dispatches per year. In the real-time markets, the system is redispatched every five minutes, so there are 105,120 real-time dispatches per year.

In general, the most economic dispatch for the Midwest ISO on a regional basis almost always results in specific local areas being net importers or net exporters. Regional transmission infrastructure enables this more efficient dispatch through the transfer of energy on a regional basis.

The important point here is that regional economic dispatch, and the associated economic benefits, occurs throughout the year, not just during the peak hour(s). Furthermore, the benefits of a market-wide economic dispatch are often more significant during off-peak hours, because fewer generation resources are required and more opportunity exists to use generation in one region to serve load in another. In any event, any effort to reduce production costs through transmission expansion that allows for a greater level of regional dispatch must be allocated throughout the year rather than just during the system peak hour(s) in order for the cost allocation to appropriately align with benefits.

Q. HOW WILL THE MVP CHARGE BE APPLIED TO EXPORT TRANSACTIONS?

A. The MUR, which I describe later in my testimony, will be applied to scheduled export transactions and scheduled wheel-through transactions as well as metered load within the Midwest ISO footprint. Thus, external transactions sinking outside the Midwest ISO will be subject to the MVP usage charge.

Q. WILL THE EXPORT CHARGE FOR MVPS APPLY TO TRANSACTIONS SINKING IN PJM?

A. Yes. While the point-to-point transmission service rates associated with firm and non-firm transmission service sinking in PJM will continue to be discounted to zero in accordance with the Commission's previous directives, transmission infrastructure applicable to the MVP cost allocation proposal represents transmission infrastructure ultimately benefiting not only load internal to the Midwest ISO, but external loads subject to public policy requirements as well. Therefore, to ensure costs are allocated in a manner roughly commensurate with benefits, it is necessary to employ the MVP usage charge to all export and wheel-through transactions, as well as internal consumption (i.e., load).

STAKEHOLDER PROCESS

Q. PLEASE DESCRIBE THE STAKEHOLDER INITIATIVES REGARDING TRANSMISSION COST ALLOCATION?

A. On August 29, 2008, the Midwest ISO filed in FERC Docket No. ER06-18-000, its annual assessment of the effectiveness and unintended consequences of the current generation interconnection-related cost allocation provisions in Attachment FF. Subsequently, the Midwest ISO and its stakeholders re-established the RECB TF to address issues with the current project inclusion and cost allocation methodologies. The RECB TF began meeting in February 2009. The RECB TF charter reflects three distinct tasks, which are designated as phases, to address the issues raised in the August 2008 filing, along with issues identified subsequently in a holistic manner.

Q. DESCRIBE THE WORK UNDERTAKEN DURING THE FIRST PHASE OF THE RECB TF.

A. Phase I focused on near-term solutions to the Generator Interconnection Project ("GIP") cost allocation methodology under Attachment FF in effect at that time, which allocated costs to load based on a LODF methodology. Due to changes in the geographic dispersion of generator projects submitted to the queue, the results of the LODF mechanism resulted in an assignment of costs different than may have been contemplated when Attachment FF rules for GIPs were first developed. The goal of Phase I was to address the near term threat to Midwest ISO membership through the implementation of an immediate correction to aspects of the current GIP allocation methodology. On July 9, 2009, the Midwest ISO and supporting Transmission Owners made a joint filing to the Commission, addressing the unintended consequences of the GIP cost allocation process by implementing an interim solution to allocate more costs of GIP-related Network Upgrades to generation interconnection customers. The interim proposal allocated 90% of the cost of 345 kV of greater GIP Network Upgrades to the Interconnection Customer and the remaining 10% allocated to Midwest ISO load on a region-wide basis. GIP Network Upgrades below 345 kV were allocated 100% to the Interconnection Customer. On October 23, 2009, the Commission conditionally accepted the proposal and directed the Midwest ISO and Midwest ISO Transmission Owners to develop a Phase II cost allocation solution and make a filing on or before July 15, 2010. The filing made today is a result of and in compliance with that directive.

Q. PLEASE DESCRIBE THE WORK UNDERTAKEN DURING THE SECOND PHASE OF THE RECB TF.

A. Phase II of the RECB TF was established to develop a cost allocation proposal that would enable investment in regional transmission expansion on a more forward looking basis, and to provide for a better solution to the unintended consequences addressed on an interim basis in Phase I of the RECB TF. While Phase II of the RECB TF was planned and underway prior to the Commission Order on October 23, 2009, the Commission Order provided additional direction and timing requirements that were incorporated into Phase II of the RECB TF. As mentioned earlier in my testimony, Phase II focused on the integration of large quantities of generation located remote from load with a focus on the addition of a new category of cost sharing for transmission projects driven primarily by the need for integration of large quantities of remote generation resources. In addition, Phase II was focused on additional improvements that may be required to the revised GIP cost allocation methodology. The results of the Phase II process, which have been developed by and fully vetted by stakeholders, is being proposed to the Commission in this filing.

Q. PLEASE DESCRIBE THE WORK TO BE UNDERTAKEN DURING THE THIRD PHASE OF THE RECB TF.

Phase III of the RECB TF is scheduled to commence in September 2010 and will evaluate all remaining transmission cost allocation and benefit criteria issues, including those applicable to Baseline Reliability Projects and Market Efficiency Projects (formerly known as Regionally Beneficial Projects), to the extent they were not previously resolved in Phases I or II. While Baseline Reliability Project cost allocation and benefit criteria were initially addressed in RECB I, and Regionally Beneficial Project cost allocation and benefit criteria were initially addressed in RECB II, the purpose of the Phase III process is to review current practices and develop further enhancements based on experience to date with the current methodologies and future trends in the Midwest ISO's region as well as in the industry.

Q. PLEASE DESCRIBE OTHER EFFORTS TO ADDRESS COST ALLOCATION IN THE MIDWEST ISO FOOTPRINT.

A. The Organization of MISO States ("OMS") identified regional transmission planning and transmission cost allocation as two of the three key strategic areas on which it planned to focus and provide leadership during the 2009-2010 time period. As a result, OMS formed an internal group known as the Cost Allocation and Regional Planning ("CARP") group, to study and develop long-term solutions for transmission cost allocation and regional transmission planning issues. The work of the RECB TF was coordinated very closely with the OMS CARP effort. Stakeholders from each of these two groups closely monitored and participated in the activities of the other group and considered feedback and ideas generated by the other group.

It is important to note that both Order No. 890 and the October 23 Order indicate that state support is important to the Commission when it comes to transmission cost allocation. For this reason, the Midwest ISO relied heavily on feedback from the OMS CARP group as well as the RECB TF. While the Midwest ISO did not ultimately adopt the OMS proposal in its entirety, the efforts of the OMS CARP and the feedback and guidance that it provided was invaluable. The proposal filed today adopts many important concepts recommended by the OMS CARP such as increased regional sharing, maintaining a siting signal for new generators interconnecting to the grid and addressing free riders through a charge to exports and wheel-throughs.

Q. DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THE LONG-TERM COST ALLOCATION SOLUTION BEING PROPOSED TODAY.

A. The RECB TF met 20 times and the OMS CARP group met 14 times since the July 9, 2009 filing to discuss, evaluate, and provide feedback on potential long-term cost allocation solutions. Both groups considered and thoroughly analyzed a number of alternative methodologies, including the Injection/Withdrawal Method, the Highway/Byway Method, the supporting Transmission Owners' Proposal, and an OMS CARP proposal that represented a hybrid between the supporting

Transmission Owners' Proposal and the Injection/ Withdrawal Method. The Injection/Withdrawal Method was a cost allocation mechanism that allocated costs to both generation and load, and on both a regional and local basis. The Highway/ Byway Method was similar to the Injection/ Withdrawal Method, but allocated costs only to load based in part on the operating voltage of the facility in question. The supporting Transmission Owners' Proposal was a methodology that allocated costs to load on a region-wide basis only for a select group of projects, designated as "Unique Purpose" Projects that were primarily intended to address public policy requirements. The OMS CARP proposal was similar to the supporting Transmission Owner Proposal, but allocated 20% of costs to generators on a region-wide basis. The RECB TF and the OMS CARP group provided significant feedback regarding various approaches and their attributes leading up to the final recommendation of the Midwest ISO.

The OMS CARP group, RECB TF, and Midwest ISO Advisory Committee were asked to vote on the four primary cost allocation alternatives under consideration[1]. The MVP cost allocation method being proposed under this filing represents a hybrid

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[1] The RECB TF votes are reflected in the May 28th informational filing pursuant to the October 23 Order

The Advisory Committee vote is reflected in the May 19 2010 meeting minutes: http://www.midwestmarket.org/publish/Document/15cf2f_128d94d853e_-7e7b0a48324a/AC%20Draft%20Minutes%2020100519.pdf?action=download&_property=Attachment

between the OMS CARP proposal and the supporting Transmission Owner proposal voted on at the RECB TF and Advisory Committee.

BENEFITS OF MVPs

Q. HAS THE MIDWEST ISO CONDUCTED ANY STUDIES TO QUANTIFY THE REGIONAL BENEFITS OF MVPS TO JUSTIFY THE ALLOCATION OF MVP COSTS ON A REGIONAL BASIS?

A. Yes, the Midwest ISO has conducted several studies to examine and quantify the various benefits that are likely accrue from the development of MVP facilities, and to evaluate the regional characteristics of projects that are similar to the proposed MVP category of projects, including projects in the Regional Generator Outlet Study ("RGOS"). These studies demonstrate the many regional benefits provided by regionally-focused transmission projects like the MVP category of projects proposed in this filing. These benefits, which accrue generally across the Midwest ISO system, justify the allocation of MVP costs on a regional, postage-stamp basis.

Q. WHAT IS THE RGOS?

A. The RGOS was established to develop a transmission expansion plan to facilitate the RPS objectives passed by most Midwest ISO member states, which generally mandate that a significant percentage of total electrical energy be obtained from renewable energy resources. To investigate the transmission enhancements that might be needed to support compliance with these requirements at the lowest total delivered wholesale energy cost, the Midwest ISO, with the assistance of state regulators and industry stakeholders, developed the RGOS to analyze potential scenarios and ultimately derive an efficient and robust transmission expansion solution to achieve the public policy established by the states.

Q. PLEASE DESCRIBE THE CONSIDERATIONS THAT WENT INTO THE RGOS AND THE OUTCOME.

A. Early phases of the study indicated that siting wind zones in a dispersed manner throughout the system – to balance local development desires with access to the region's best wind locations – results in a set of wind zones that help to optimize the overall system cost to meet renewable energy requirements. The means by which these distributed wind zones were identified was endorsed by the states through the Upper Midwest Transmission Development Initiative ("UMTDI") in the RGOS I work effort and has been affirmed by the Midwest Governors' Association. Through the RGOS study process, the Midwest ISO has determined that the best solution is a transmission "overlay," often referred to as a transmission highway, encompassing all Midwest ISO states. This solution was premised on a distributed set of wind zones, each with varying capacity factors and distances from load. Furthermore, the RGOS study narrowed the focus to the development of three transmission expansion scenarios to integrate wind in the designated zones: (1) a Native Voltage approach limiting transmission expansion to current infrastructure voltage levels; (2) 765 kV, which allows for expansion of the 765 kV grid into the Midwest ISO footprint; and (3) Native Voltage with Direct Current ("DC") transmission, an approach to enable deliverability across long distances.

Q. WHAT ARE THE NEXT STEPS

A. The RGOS focused on the development of holistic system solutions meeting long-term needs for the integration of renewable resources into the transmission system. Once such solutions were identified, it was necessary to then identify an initial sequencing of these projects to enable transmission to begin to be built, without committing to the full buildout before it was needed. Midwest ISO staff has developed a set of potential transmission projects that have the attributes of and could qualify as MVPs, and which represent the "starter projects" that would be initially sequenced to meet identified public policy mandates. This set of "starter projects" is being determined using a number of factors, including transmission corridors identified in multiple Midwest ISO studies (i.e., the RGOS and another study known as the "Top Congested Flowgate Study", as well as ongoing analyses as part of the expansion planning and generation interconnection queue study process), synchronizing generator interconnection queue locations with RPS timing needs, and the probability of construction. It is anticipated that these starter projects, or projects like them, will be developed within 5-10 years after the approval of the MVP cost allocation methodology. The list of potential MVP starter projects, attached as Tab J to this filing, includes transmission lines in every region of the Midwest ISO footprint and represents about $4.6 billion in investment in the Midwest ISO to be developed over the next 10 years.

Q. WHAT KINDS OF BENEFITS WILL THESE "STARTER PROJECTS" PROVIDE?

A. These MVP starter projects will help advance the integration of renewable resources to meet state public policy requirements. These projects will also alleviate major areas of congestion on the Midwest ISO system that will allow more efficient delivery of energy to load. This enhanced deliverability of energy will help loads meet their state public policy requirements because it will reduce the amount of wind energy that must be curtailed due to bottled up generation. As shown in the testimony of John Lawhorn, simulations of this enhanced deliverability indicate a reduction in wind curtailments on the order of 25% in the East Planning Region. Development of the MVP starter projects will also ease the burden of interconnection costs for new generators in the queue because, as explained in the testimony of Eric Laverty, the Midwest ISO expects the interconnection costs for most new generators to decrease significantly as the costs of MVP projects are allocated under the MVP cost allocation methodology.

Q. ARE THERE BENEFITS TO MVP PROJECTS BEYOND SATISFYING PUBLIC POLICY NEEDS?

A. There will be many additional regional benefits that public policy driven MVP's will provide. The kind of regional transmission projects that are being proposed to satisfy current state RPS (which the Midwest ISO anticipates will be primarily sourced from wind resources in the Midwest ISO) will provide benefits driven by reductions in congestion and losses, such as reduced aggregate production cost of delivered energy, and maintaining or reducing the Midwest ISO Planning Reserve Margin, as well as broadly-shared reliability benefits by facilitation of upgrades needed to ensure continued satisfaction of reliability standards. Each of these categories of benefits is further discussed in the testimony of John Lawhorn.

Q. HOW WILL THE DEVELOPMENT OF MVPS REDUCE PRODUCTION COSTS FOR THE MIDWEST ISO IN THE NEAR TERM AND LONG TERM?

A. MVP's will provide production cost benefits to the Midwest ISO region by reducing congestion and allowing greater access across the footprint to the most economic generation available. Generally, the same transmission lines that will allow the delivery of renewable resources will also relieve major areas of congestion across the footprint due to the integrated nature of the transmission system. Looking at the initial list of MVP starter projects, the Midwest ISO is expecting an annual potential adjusted production cost savings from the MVP starter projects ranging from $297 million to $423 million in year 2015 and $402 million to $1.3 billion in year 2025 based on the analysis described in the testimony of John Lawhorn. These savings will be spread almost equally across the three Midwest ISO Planning Regions, further illustrating the regional nature of the benefits MVP's are expected to provide. This distribution of production cost benefits is roughly commensurate with the distribution of energy consumption, further supporting the MVP's broad allocation of costs to all users of the Transmission System. Notably, through reduction of transmission congestion costs, this benefit will accrue to all market participants that rely on the Midwest ISO to transmit energy, i.e., loads, exports, and drive-through service.

Q. WILL THE INTRODUCTION OF MVPS REDUCE LOSSES ON THE MIDWEST ISO SYSTEM?

A. Yes. As described in the testimony of John Lawhorn, the Midwest ISO is estimating a reduction of about 1,500 to 2,000 GWh in annual transmission system losses when the MVP starter projects are put into service. This translates into an additional annual cost savings potential of about $68 - $104 million. Reducing system losses also reduces the amount of capacity reserves that are required to maintain reliability. If these peak demand losses are reduced, the system will need less reserves to be reliable. Assuming $960,000.00 per MW/year as a typical cost of new entry and a 15% reserve requirement, a 100 MW reduction in peak demand losses would result in $110 million of savings in deferred capacity investment.

Q. HOW WILL THE DEVELOPMENT OF MVPS AFFECT THE RESERVE MARGIN REQUIREMENT IN THE MIDWEST ISO?

A. In addition to reducing reserves due to reduced losses, MVPs, by reducing Transmission System congestion will also allow the Midwest ISO to maintain and potentially further lower the Planning Reserve Margin requirement for Midwest ISO Load Serving Entities. The Planning Reserve Margin for the 2010/11 Planning Year for the Midwest ISO is 15.4%. As shown in the 2009 Midwest ISO Loss of Load Expectation ("LOLE" report, as congestion on the system increases, the amount of reserves required to maintain reliability also increases, because congestion limits the pool of resources available to serve portions of the footprint. By having a smaller pool of resources to use, it becomes more probable that a loss of load could occur due to forced outages of resources and variations from the demand forecast. For example, the 2009 LOLE study shows a 2.3% increase in reserves required over the 10 year study period due to increased congestion. Based on the $960,000.00 per MW/year cost of new entry, Midwest ISO Load Serving Entities would save about $2.3 billion in deferred capacity investment (2,400 MW based on a 2.3% potential increase in reserves) by maintaining the current reserve requirements. If congestion can be reduced from current levels due to the addition of transmission, as illustrated in the 2010 Midwest ISO LOLE report, then the Planning Reserve Margin could be reduced from the current 15.4%. The 2010 study shows that with the inclusion of planned reliability upgrades and some proposed facilities, the Planning Reserve Margin could be reduced to 14.9% for the region. Although the impact on reserve margins for the MVP starter projects has not yet been evaluated, it is reasonable to assume that, given the congestion benefits described previously, some amount of reserve margin benefit will accrue. Even a relatively small reduction of 0.5% in reserve requirements would result in the deferral of about 500 MW of capacity investment, saving approximately $500 million. This study did not even include any candidate MVP projects. With those projects included, the Midwest ISO anticipates the further reduction of congestion with a concomitant reduction in Planning Reserve Margin.

I note that the because the recent economic downturn has moderated or reduced capacity needs in the Midwest ISO, capacity-related benefits of MVPs may not be fully realized in the next few years. However, loads and exports are not likely to bear MVP costs in the next few years, given project lead times.

Another regional benefit that MVP projects provide is that it allows the Midwest ISO to exploit significant load diversity across the footprint to keep reserve margins lower than they would have been. According to the Midwest ISO's Value Proposition[2] an estimated $217-271 million of savings per year is realized due to load diversity. These benefits are annual benefits and are in

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[2] http://www.midwestmarket.org/page/Value+Proposition

addition to the deferred investment benefits described above.

Q. HOW DO THESE INDICATIVE ECONOMIC BENEFITS COMPARE TO THE LIKELY COSTS OF THE STARTER PROJECTS?

A. Summing these indicative annual economic benefits, i.e., production cost savings, reduction in transmission losses, and diversity driven reductions in Planning Reserve Margin, suggests economic benefits in 2015 of $582 million (assuming the low-end estimates above) to $798 million (assuming the high-end estimates above). The higher production cost savings, as found by Mr. Lawhorn, and savings in deferred capacity investment, could add billions of dollars to that indicative estimate in the long run. By contrast, the estimated annual transmission revenue requirement for all "starter" projects is $675 million, based on the Midwest ISO weighted average fixed charge rate of 15% over 40 years, and estimated combined capital costs for all starter projects of $4.6 billion. I should stress that these figures all are rough, indicative estimates. However, what this exercise underscores is that MVP-type projects are likely to produce very substantial economic benefits, and that these benefits will redound to the region as a whole. Moreover, these benefits do not include the very real, but harder to quantify, benefits of satisfying regional public policy objectives and ensuring regional reliability.

Q. WHAT KINDS OF RELIABILITY BENEFITS WILL MVP'S PROVIDE?

A. An MVP may provide reliability benefits in several different ways. By its very nature, an MVP will always provide some enhancement to system robustness and will thereby make the system more resilient to unforeseen contingencies threatening the reliable delivery of service to customers. More specifically, to the extent that an MVP is driven by the requirement to enable the reliable and efficient delivery of energy to meet state or federal energy policy mandates, such delivery will generally not be possible within the reliable design limits of existing infrastructure without the addition of MVPs. Under such circumstances, the MVP is necessary to facilitate underlying policy mandates, such as RPS. For instance, to the extent that wind generated energy is being relied upon to meet state RPS requirements, MVPs will be necessary to reliably transmit the energy from the wind rich areas within the Midwest ISO to the load that is subject to the RPS requirements. In addition, it is quite likely that an MVP can be designed to optimize its ability to address both local area reliability issues and regional energy transfer needs, eliminating the need for some addition transmission upgrades that may have otherwise been required.

Q. HAS THE MIDWEST ISO ANALYZED WHETHER MVP-TYPE PROJECTS WILL BE USED BY TRANSMISSION CUSTOMERS ON A REGIONAL BASIS?

A. Yes, and that analysis indicates that MVP-type projects overwhelmingly support regional uses of the grid. Specifically, the Midwest ISO performed a number of transmission usage studies on the full set of projects that the RGOS has currently identified as needed to meet the current RPS requirements and goals in the Midwest ISO. As relevant here, these studies assessed whether, and the extent to which, certain transmission system enhancements would be used on a regional basis as opposed to a local basis. Local usage was defined as the use of transmission facilities to deliver energy from local generation sources to local load, and regional usage was defined as all other uses of the transmission facilities. The final study was designed to study a sample of 219 hours in a given test year (2.5% sample), where the hours were distributed throughout the year in a manner that very closely approximated the annual load duration curve. Furthermore, usage was studied on various classes of transmission facilities, including transmission facilities proposed in the long-term transmission plan to facilitate current RPS objectives. These transmission facilities in the long-term transmission plan, which include over two hundred 345 kV and 765 kV facilities, are the best available representation of the type of future transmission facilities that would likely be categorized as MVPs.

Q. WHAT DID THE TRANSMISSION USAGE STUDIES SHOW?

A. The mileage-weighted analysis of these lines indicates that their use would be overwhelmingly, *i.e.* 80% regional. Since virtually every transmission improvement project necessarily will be used locally to some extent (*i.e.*, 100% regional usage is almost never achieved), this very high level of regional usage underscores that these types of facilities are essentially for the purpose of strengthening the regional transmission system, for the use and benefit of all market participants that use the regional grid. Given the high level of regional use of MVP-type projects, and the many other concrete benefits that MVP-type projects provide that are broadly shared across the region, allocating the costs of MVPs to all loads and exports based on their use of the transmission system is just and reasonable.

MULTI VALUE PROJECTS

Q. WHAT TYPES OF TRANSMISSION PROJECTS ARE SUBJECT TO COST SHARING TODAY AT THE MIDWEST ISO?

A. There are three types of defined transmission projects that are subject to cost sharing today at the Midwest ISO. A Baseline Reliability Project is defined as a project required to address compliance with North American Electric Reliability Corporation ("NERC") or Regional Entity reliability standards, and may be subject to cost sharing using the LODF methodology as described in the Tariff and Business Practice Manuals. A Regionally Beneficial Project is defined as a project that provides economic value through reduction of production costs and Locational Marginal Prices ("LMP") that meets specified benefit-to-cost thresholds. (In the instant filing, the Midwest ISO is proposing to change the name of Regional Beneficial Projects to Market Efficiency Project, a term that presents a more accurate description of the type of project currently classified as a

Regionally Beneficial Project.) Finally, 10% of the Network Upgrades associated with a Generation Interconnection Project may be cost shared on a regional basis if the Network Upgrades represent transmission facilities that operate at a nominal voltage equal to or greater than 345 kV.

Q. WHAT ADDITIONAL TYPES OF TRANSMISSION PROJECTS ARE PROPOSED FOR COST SHARING AT THE MIDWEST ISO UNDER THIS FILING?

A. Under the current filing, the Midwest ISO is proposing to create the MVP. The MVP is a fourth type of defined project that will be subject to cost sharing on a regional basis. The new MVP project category is designed to include large regional projects developed and proposed via the top-down / bottom up transmission expansion planning process (as opposed to the generation interconnection planning process) for the purpose of meeting documented public policy requirements such as RPS objectives or providing economic value-based benefits on a wide basis. These types of projects are not presently subject to a cost-sharing methodology, which underlies the need for this new category.

Q. HOW WILL AN MVP BE DEFINED?

A. An MVP is defined as one or more Network Upgrades that address a common set of Transmission Issues and meet at least one of three general criteria designated in Attachment FF as Criterion 1, Criterion 2, and Criterion 3. Criterion 1 is the public policy criterion and specifies that any transmission project driven by the need to enable the reliable delivery of energy in support of a documented public policy mandate or law qualifies as a MVP. Criterion 2 specifies that a transmission project that provides multiple types of economic value across multiple pricing zones qualifies as a MVP. Criterion 3 specifies that a transmission project that addresses at least one Transmission Issue which is driven by a compliance requirement with a NERC or Regional Entity standard and provides economic value to multiple pricing zones will qualify as a MVP. Also, to the extent that the incremental costs of a project beyond the base transmission requirement are exceeded by the benefits, those costs may be eligible for sharing under the MVP methodology. It is important to note that there are a number of additional qualifiers that apply as well. For example, there is a requirement that the capital cost of the project must exceed the lesser of $20 million or 5% of the net transmission plant of the constructing Transmission Owner and other similar types of requirements. These additional qualifiers are outlined in Section II.C.2 of Attachment FF.

Q. CAN AN MVP INCLUDE LOWER VOLTAGE FACILITES, AND IF SO, ARE THEY SUBJECT TO THE SAME COST SHARING?

A. An MVP must include construction or improvement of at least one facility that operates above 100 kV. If this requirement is met, lower voltage facilities can be associated with an MVP and will qualify for cost sharing to the extent that construction or improvement of the lower voltage facility is driven solely by the construction or improvement of higher voltage facilities associated with the MVP project.

For example, if an MVP starts out as the construction of a 765 kV transmission line, and installation of that transmission line results in an overload on a nearby 69 kV transmission line that would not have otherwise occurred, the costs to upgrade the 69 kV line can be included in the MVP cost allocation. However, if there is a loading problem on the 69 kV line already that must be addressed regardless of whether the 765 kV line is built, the costs to upgrade the 69 kV line would not be subject to cost sharing under an MVP. The manner in which transmission "underbuild" is evaluated as part of the overall transmission project is described further in the testimony of Jeff Webb.

Q. HOW DOES A MVP DIFFER FROM A BASELINE RELIABILITY PROJECT AND MARKET EFFICIENCY PROJECT?

A. A Baseline Reliability Project is driven by compliance with NERC and Regional Entity reliability standards, and its costs are primarily shared locally. A Market Efficiency Project is driven by the ability to reduce production costs and load LMPs in a manner that meets predetermined benefit-to-cost ratio thresholds. These typically will be viewed as local congestion relief projects. By contrast, a MVP is a project that is driven either by requirements to comply with documented public policy requirements, by providing economic value to Transmission Customers on a regional basis, or by providing material economic benefits in addition to meeting regional reliability standards. The MVP

Cost Allocation methodology is intended to be a complement to, rather than a replacement for, the existing cost allocation methodologies which address transmission generally characterized as local in nature. For example Baseline Reliability Projects, even those at high voltage levels, that do not provide significant additional regional benefits would not qualify as an MVP and those costs would appropriately be allocated on a predominately local basis as is done today.

Q. HOW WOULD A PROJECT BE CLASSIFIED IF IT QUALIFIES FOR MULTIPLE TYPES OF DEFINED COST SHARING PROJECTS?

A. If a project qualifies as both a MVP and a Baseline Reliability Project, the project would be classified as a MVP. In addition, if a project qualifies as both a MVP and a Market Efficiency Project, the project would be classified as a MVP. Any project qualifying as all three types of projects would be classified as a MVP as well.

Q. HOW IS IT DETERMINED IF A POTENTIAL NETWORK UPGRADE QUALIFIES AS A MVP VERSUS A GENERATOR INTERCONNECTION PROJECT?

A. If a transmission project with Network Upgrades is recommended for construction approval in a specific planning cycle solely as a result of the generation interconnection planning process, that is, solely as a result of processing the generation interconnection queue, the project will be classified as a Generator Interconnection Project and not considered a MVP. If a project qualifies as a MVP and is recommended for construction both by the generation interconnection planning process and the transmission expansion planning process within the same planning cycle, the project will be classified as a MVP.

Q. COULD YOU PLEASE BRIEFLY EXPLAIN THE DIFFERENCE BETWEEN THE GENERATION INTERCONNECTION PLANNING PROCESS AND THE TRANSMISSION EXPANSION PLANNING PROCESS?

A. The generation interconnection planning process is the process of planning transmission upgrades, including Network Upgrades, that are necessary to support the interconnection of specific Generation Resources that have requested interconnection and are within the generation interconnection queue. The parts of that process subject to change in this filing are discussed in the testimony of Eric Laverty. On the other hand, the transmission expansion planning process, which is discussed in more detail in the testimony of Jeff Webb, is the process of planning transmission Network Upgrades in response to more general compliance and value drivers including, but not necessarily limited to, projected reliability issues driven by load growth or public policy requirements and opportunities to increase economic value to Transmission Customers through reductions in transmission congestion and losses.

Q. HOW WILL THE MIDWEST ISO DETERMINE THAT A SPECIFIC PROJECT QUALIFIES AS A MVP BASED ON CRITERION 1 IN SECTION II.C.1.a OF THE PROPOSED ATTACHMENT FF?

A. Criterion 1 is the public policy criterion. Under the transmission expansion planning process, the Midwest ISO will analyze the transmission system under future conditions to determine the ability of the Transmission System to comply with a number of requirements, including public policy requirements. In modeling future generation, the starting point is always to use existing generation, subtract planned retirements, and then add in planned generation with executed Interconnection Agreements. However, the resulting future generation fleet model is rarely sufficient to meet forecasted demands and planning reserve margin requirements in the long-term planning horizon. In addition, the modeled future generation fleets are rarely sufficient to satisfy public policy requirements such as the state RPSs that are currently in place. Therefore, the Midwest ISO, working in conjunction with stakeholders and using the generation queue as a guide, must make projections as to the location and type of generation that will exist in the future above and beyond the existing generation fleet or proposed generation with executed interconnection agreements. These projections take into account, among other factors, the relative costs of generation capacity and transmission expansion as well as the suitability of various locations for specific types of generation resources.

To the degree that specific transmission projects must be proposed to accommodate projected future generation required to satisfy public policy requirements, these projects will qualify as MVPs. It is important to reiterate that the transmission expansion process is not driven directly by the generation queue itself, but instead by knowledge of future compliance issues related to public policy requirements and the desire to ensure the Transmission System is expanded in the best possible manner over the long-run, a task that is difficult to achieve under the queue-driven incremental generation interconnection planning process.

Q. HOW WILL THE MIDWEST ISO DETERMINE THAT A SPECIFIC PROJECT QUALIFIES AS A MVP BASED ON CRITERION 2 IN SECTION II.C.1.b OF THE PROPOSED ATTACHMENT FF?

A. The two key requirements of Criterion 2 are that a project provide multiple types of economic value and that the economic value be spread across multiple pricing zones. Therefore, the Midwest ISO would first have to determine the specific economic benefits associated with the proposed project, and then ensure there are multiple types of economic benefits. For example, if a project were to reduce transmission congestion and losses, but these reductions represented only production cost benefits, the project could not qualify as a MVP based on this criterion. Once it has been established that there are multiple types of economic benefits, such as the reduction of planning reserve margins and the reduction of energy and operating reserve production costs, it is necessary to ensure that the economic benefits are in excess of the project's costs. That is, economic value is only realized when economic benefits exceed the associated project's costs. This verification is made by calculating a Total MVP Benefit-to-cost Ratio, where the Total MVP Benefit-to-cost Ratio is the ratio of economic benefit to project cost, with economic benefit being equal to the present value of the financially quantifiable economic benefits projected for the first 20 years of the project's life and project cost is equal the present value of the projected annual revenue requirements of the project for the first 20 years of the project's life. Once it has been verified that the project has a Total MVP Benefit-to-cost Ratio greater than 1, it is necessary to ensure that value is present in multiple pricing zones. This is accomplished by estimating the allocation of projected benefits and costs to each pricing zone to ensure multiple pricing zones realize economic value.

Q. WHY IS THE TOTAL MVP BENEFIT-TO-COST RATIO LIMITED TO THE FIRST 20 YEARS OF A PROJECT'S LIFE?

A. During the stakeholder process, two schools of thought evolved regarding the calculation of benefit-to-cost ratios. One philosophy was based on the premise that the benefit-to-cost ratio should be projected for the entire life of a project, otherwise the transmission planning process may not maximize transmission value in the long-run or capture all of the potential benefits (or costs) associated with a transmission project. The opposing philosophy was based on the ideas that i) some payback mechanism should be embedded into any the benefit-to-cost methodology, ii) it is difficult to project with any certainty the economic benefits associated with a project toward the end of the project's life given typical life spans of 40 or more years, and iii) economic value beyond 20 years will be significantly diminished in the present value calculation. As a compromise, the Midwest ISO is proposing to use a 20 year economic analysis period, both for MVP evaluation and overall transmission expansion planning economic value evaluation. The Midwest ISO believes this strikes the right balance between the desire to maximize the long-term value of the transmission system and the desire to manage payback expectations and potential future uncertainties.

Q. PLEASE PROVIDE AN EXAMPLE OF AN ECONOMIC DRIVEN PROJECT THAT WOULD QUALIFY AS A MARKET EFFICIENCY PROJECT BUT NOT A MVP UNDER CRITERION 2?

A. A project that provides economic value in the form of production cost reductions through relief of transmission congestion and reduction of energy losses in a localized area (*e.g.*, load pocket), but provides no other economic benefits, may qualify as a Market Efficiency Project if the appropriate benefit-to-cost thresholds are satisfied, but would not qualify as MVP because only one type of economic value (*i.e.*, production cost reductions) is provided, the benefits are not across multiple pricing zones, and no Transmission Issues related to NERC or Regional Entity standards are being addressed.

Q. HOW WOULD THE MIDWEST ISO DETERMINE THAT A SPECIFIC PROJECT QUALIFIES AS A MVP BASED ON CRITERION 3 IN SECTION II.C.1.c OF THE PROPOSED ATTACHMENT FF?

A. The two key requirements of Criterion 3 are that a project address both a Transmission Issue driven by a projected violation of a NERC or Regional Entity reliability standard and produce economic value in multiple pricing zones. Therefore, the Midwest ISO would first have to determine that the project resolves a projected violation of a NERC or Regional Entity standard. If it is determined that the proposed project resolved a projected violation of a NERC or Regional Entity standard, then the next step would be to determine the specific economic benefits associated with the proposed project to ensure that they exceed the project's costs using the same Total MVP Benefit-to-cost Ratio that was used in Criterion 2. Once it has been verified that the project has a Total MVP Benefit-to-cost Ratio greater than 1 it is necessary to ensure that value is present in multiple pricing zones. This is accomplished by estimating the allocation of projected benefits and costs to each pricing zone to ensure multiple pricing zones realize economic value.

MVP RATE DESIGN

Q. WHAT IS THE MULTI-VALUE PROJECT USAGE RATE?

A. The Multi-Value Project Usage Rate (MUR) is an energy based charge used to recover the MVP Annual Revenue Requirements from monthly withdrawals, as described and calculated in accordance with Attachment MM of the Tariff. Monthly withdrawals refer to Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

Q. HOW ARE THE MONTHLY NET ACTUAL ENERGY WITHDRAWALS CALCULATED?

A. For a Commercial Pricing Node, the Monthly Net Actual Energy Withdrawals are calculated as the volume, in MWh, that flows out of the Transmission System during the Operating Month at a specified location that is equal to the net positive sum of (1) the hourly time-weighted average of the Metered volume of the Commercial Pricing Node and (2) the hourly time-weighted Actual Energy Injections for Demand Response Resources and Emergency Demand Response resources associated to a Load Zone.

Q. WHY WAS A NETTING APPROACH USED TO CALCULATE MONTHLY ACTUALLY ENERGY WITHDRAWALS, AS OPPOSED TO A SIMPLE SUMMATION?

A. There are three primary reasons for using a netting approach as opposed to a simple summation: demand response, storage resources, and station service during an extended generation outage. For demand response, the netting avoids charging Load Serving Entities for load not actually consumed. For pump storage, which at times withdraw from and at times injects into the transmission system, the netting approach charges pump storage resource for their net usage of the transmission system. For station service during an extended generation outage, the netting approach charges generation only in those months that they are net negative (withdrew more than injected) for the month.

Q. PLEASE EXPLAIN THE RATIONALE FOR USING A QUANTITY-WEIGHTED APPROACH TO DISTRIBUTING THE MVP ANNUAL REVENUE REQUIREMENTS TO EACH MONTH, RATHER THAN A SIMPLE MONTHLY AVERAGE?

A. MVP Annual Revenue Requirements are collected based on usage, and as such, the MVP Annual Revenue Requirements should be distributed to each month based on usage. A simple average assumes that usage is the same for each month of the year, which is not the case. Using monthly withdrawals as the basis for the quantity-weighting factor delivers certain improved efficiencies, as compared to a simple average. The Monthly MVP Revenue Requirements will fluctuate month-to-month, as will the Monthly Net Actual Energy Withdrawals, in relative proportion, by quantity-weighting the revenue requirements by the prior year's monthly withdrawal data. This approach effectively flattens the monthly rate, allowing for better forecasting and budgeting.

OTHER ISSUES

Q. HOW WILL THE MVP USAGE CHARGE APPLY TO NEW TRANSMISSION OWNERS JOINING THE MIDWEST ISO?

A. The MVP usage charge will be phased in over a transition period, with 25% of the charge applicable in the first full year of membership as a Transmission Owner, 50% of the charge applicable in the second full year of membership, 75% of the charge applicable in the third full year of membership and 100% of the charge applicable thereafter.

Q ARE EXITING TRANSMISSION OWNERS OBLIGATED TO PAY FOR MVPS APPROVED DURING THEIR MEMBERSHIP IN THE MIDWEST ISO?

A. Yes. Transmission Owners that withdraw from the Midwest ISO will be obligated to pay for the remaining MVP costs allocated to load served by the Transmission Owner if the MVP is approved prior to the effective date the Transmission Owner withdraws from the Midwest ISO, but after the Transmission Owner becomes a member of the Midwest ISO

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT

District of Columbia)
)
City of Washington)

Jennifer K. Curran, being duly sworn, deposes and states: that she prepared the Prepared Direct Testimony of Jennifer K. Curran and the statements contained therein are true and correct to the best of her knowledge and belief.

Jennifer K. Curran

SUBSCRIBED AND SWORN BEFORE ME, this 14 day of July, 2010.

Notary Public
My Commission Expires:

My Commission Expires
September 30, 2013