BEFORE THE MINNESOTA PUBLIC UTIILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Site Permit of Morgan Wind Acquisition Group LLC for a Large Wind Energy Conversion System	MPUC Docket No. IP-6723/WS-09-360

PETITION TO AMEND THE LWECS SITE PERMIT FOR MORGAN WIND ACQUISITION GROUP LLC

I. Introduction

Morgan Wind Acquisition Group LLC ("Morgan") respectfully petitions the Minnesota Public Utilities Commission ("MPUC") for an order amending the Large Wind Energy Conversion System ("LWECS") Site Permit (the "Permit") for its 31.5 MW LWECS Project (the "Project"). Morgan requests that the deadlines for construction to start and to obtain a power purchase agreement ("PPA") be extended by two years.

Morgan was unable to meet the 2011 deadline due to the total uncertainty of cost allocation for the planned Brookings County, SD to Hampton, MN 345 kV transmission line project (the "Brookings Line"), as detailed below. Fortunately, recent orders issued by the Federal Energy Regulatory Commission ("FERC") have created opportunities for development to move ahead.

Morgan will lose the ability to take advantage of those opportunities if the MPUC does not amend the Permit, as allowed by Minn. R. 7854.1300, subp. 2. This amendment request is similar to those approved by the MPUC for the Comfrey Wind Energy Project (March 2011, MPUC Docket No. IP-6630/WS-07-318) and the Sibley Wind Substation LLC Project (October 2011, MPUC Docket No. IP-6666/WS-08-208).

II. Petition

A. Overview of the Morgan Project

The Project is located in Southwest Minnesota, near the city of Morgan and on the border of Redwood and Brown counties. The total Project area covers approximately 10,800 acres of agricultural land in Eden Township in Brown County and Morgan Township in Redwood County. Land use in the area is mainly for production of corn, soybeans, hay and vegetables. No public waters, wetlands or forested areas will be impacted by construction of the Project.

The Project site has unique access to transmission service and a good wind resource. Xcel Energy has a 69 kV line that runs along the Project's entire southern border. The planned Brookings Line actually crosses the Project site. The wind resource in the area is strong enough to support an economically healthy wind generation project.

Morgan also has good relations with its landowners. There are 32 separate lease agreements that will provide income to well over 100 people. The Project qualifies as a C-BED facility, and has resolutions of support from both Brown and Redwood counties.

Morgan intends to use 19-21 turbines rated between 1.5 and 1.65 MW, yielding a total nameplate capacity of 31.5 MW, as allowed by the Permit. The turbines will be located at least 1,200 feet from all residences in the area, including those of both participating and non-participating landowners. Morgan is not proposing any changes to the Permit beyond the deadlines, the layout and proposed turbines remain the same, and all conditions of the Permit will be met.

B. Development History

1. Initial project development.

Project development started in 2006 with conception, negotiation of lease agreements to secure rights to approximately 4,500 acres of land, and conducting wind studies. A Large Generator Interconnection Agreement ("LGIA") was executed with the Midwest Independent Transmission System Operator ("MISO") and Xcel Energy on October 3, 2008. Morgan's first met tower began operation in December, 2008 and a second was added in April, 2009.

Morgan filed its application for the Permit on May 22, 2009. About 40 people attended a public information meeting held in Morgan on September 15, 2009. Topics of discussion at the meeting included the location of project facilities, depth of underground collector lines, potential impacts to aerial application of herbicides and road impacts. The MPUC granted the Permit on December 22, 2009.

Morgan encountered two problems developing the Project. One was related to notice. Morgan's parent company, Midwest Wind Finance, LLC, initiated a staff reduction at the end of 2009. Morgan's project manager was impacted by that reduction, and was notified of that decision during the same week the Permit was issued. Unfortunately, the former project manager failed to send the Permit to landowners, as required by section III. K. 9 of the Permit, before the end of employment in early January, 2010. The former project manager also failed to inform Morgan's management of the requirement, and management did not learn of the failure to provide notice until March 26, 2012.

Morgan's primary problem, however, is that the Project is part of the well-known MISO Study Group Five ("Group 5"). Morgan was therefore subject to the same uncertainty in allocation of the cost of the Brookings line that impacted many other projects, including the

Comfrey and Sibley projects previously mentioned. Morgan's development obstacles stemming from its inclusion in Group 5 are the subject of the following section.

2. The MISO interconnection process prevented Morgan from completing development within two years.

Morgan started the MISO interconnection process in 2006 as project number G626. The project was assigned to Group 5 along with 32 other projects in Southwest Minnesota, Northwest Iowa and Eastern South Dakota.[1] A limited review of Group 5's saga is relevant to understanding why Morgan has not obtained a power purchase agreement ("PPA") or completed development.

MISO completed the study reports for the various facilities required for Group 5 to interconnect in the fall of 2007.[2] These studies were contemporaneous with planning and permitting work for the CapX2020 project, which includes the Brookings Line. MISO attempted to allocate the entire cost of the Brookings Line, estimated at $700 million, to 19 of the Group 5 projects.[3] Morgan was in that group, and the estimated cost to connect its 31.5 MW project was $14,000,000. That was a very significant amount, especially when the total cost of the Project was estimated to be $74,000,000. That interconnection cost, however, was only a minimum number. Morgan's cost would go up if any of the other 18 projects elected to halt development instead of paying for the Brookings Line.[4] Given the extreme costs of that transmission line, it seemed highly likely that other projects would indeed leave the queue.

[1] *Midwest Independent Transmission System Operator, Inc*., 129 F.E.R.C. ¶ 61,019 at note 8. (Federal Energy Regulatory Commission, Order Conditionally Accepting Amended and Restated Generator Interconnection Agreement, October 9, 2009), attached as Exhibit A.
[2] 129 F.E.R.C. ¶ 61,019 at note 8
[3] *Id*. at Para. 5.
[4] *See id*.

Many Group 5 project developers and other interested parties took issue with MISO's attempt to force the Group 5 projects to pay for the Brookings Line. One Group 5 member, Community Wind North ("CWN"), took the matter to the Federal Energy Regulatory Commission ("FERC") in August 2009 by requesting that its LGIA with MISO be filed unexecuted.[5] This proceeding affected all Group 5 projects, including Morgan's.

On October 9, 2009, the FERC ultimately ruled that MISO's attempt to allocate the entire cost of the Brookings Line to the 19 Group 5 projects was not "shown to be just and reasonable, and must be rejected."[6] The basis for the FERC's order was that MISO had not demonstrated that the Brookings Line was required "primarily for the delivery of new wind energy resources."[7] MISO was ordered to remove language from the CWN GIA that allocated responsibility for the costs of the Brookings Line to the Group 5 projects.[8] MISO and others, however, requested a rehearing of the FERC's order.

On May 20, 2010, the FERC clarified its October 2009 order and repeated that MISO's attempt to allocate the entire cost of the Brookings Line to the 19 Group 5 projects was unsupported by the evidence.[9] Specifically, the FERC found that the Brookings Line was developed as part of the CapX2020 project to serve needs beyond the interconnection of the Group 5 projects.[10] As a result, the entire cost of the Brookings Line could not be allocated to the subset of Group 5. Instead, those projects could only be allocated costs equal to the amount

[5] *Id* at Para. 1.
[6] *Id* at Para. 24.
[7] 129 F.E.R.C. ¶ 61,019.
[8] *Id*. at Para. 29.
[9] 131 F.E.R.C. ¶ 61,165 at Para. 2, attached as Exhibit B.
[10] 129 F.E.R.C. ¶ 61,019. at Para. 18.

of the least-cost upgrades required to connect them to the transmission system.[11] Morgan expects that this order will dramatically reduce its interconnection costs.

MISO then launched a restudy because, according to MISO, several Group 5 projects had dropped out of the interconnection queue and because MISO had to find an alternative to the Brookings Line for the purpose of cost allocation for the Group 5 projects.[12] This added further delays to Morgan's interconnection process. Fortunately, recent orders from the FERC are expected to ease Morgan's development path.

3. Morgan has diligently worked to develop the Project despite the uncertainty, and recent queue reform efforts have eased the path to final development of the Project.

The uncertainty related to the Brookings Line was a significant obstacle. Morgan had to include its anticipated $14,000,000 share of the Brookings Line, including the probability of that cost increasing substantially, in its bids for PPAs. Morgan believes that the need to price-in that cost resulted in bids that were not competitive. A proposal was submitted to Xcel in February 2009. Another was submitted to Great River Energy ("GRE") in June 2009. That was followed by a proposal to the Central Minnesota Municipal Power Agency ("CMMPA") in July 2009. The proposals to GRE and CMMPA were made in conjunction with a third party, Phaze, Inc., that Morgan was negotiating with for the future of the Project. Morgan also allowed Phaze to take the lead in attempting to negotiate a PPA with Xcel and other potential offtakers during 2009 and 2010. While Phaze did pursue sales agreements diligently, these efforts did not result in a PPA and Morgan's relationship with Phaze has terminated. Additional attempts to enter into a PPA were made in 2011.

[11] The FERC was careful to note that this does not mean that the Brookings Line cannot be built, only that the Group 5 projects cannot be required to pay for the entire project.
[12] *Id* at Para. 26, note 41. The FERC, however, noted that the MISO tariff required the restudy to be completed within 60 days if possible. *Id*. at Para. 45.

Lack of a PPA led Morgan and MISO to agree in mid-2011 to place the LGIA into suspension for 36 months, retroactive to June 3, 2009, rather than exhaust Project funding to meet large milestone payments required under the LGIA. The LGIA will come out of suspension in June, 2012.

MISO and interconnection stakeholders recognized several years ago that the interconnection process was not working. MISO initiated a queue reform process that ultimately produced several key orders from the FERC. In one order, the FERC approved a proposal to modify MISO's transmission planning process to allow some transmission projects to be designated as Multi-Value Projects ("MVPs").[13] Projects may be designated as MVPs if they "enable reliable and economic delivery of energy in support of documented energy policy mandates or laws that address . . . multiple reliability and/or economic issues affecting multiple transmission zones."[14] The cost of MVP facilities, including the Brookings Line that confounded Group 5, will be shared among all load in and exports from MISO's area of control.[15] Morgan anticipates that this order will reduce its interconnection costs.

Morgan and many other Group 5 developers paid close attention to the queue reform efforts in late 2011. Morgan was understandably concerned with expending further capital to extend the permit while the outcome of the queue reform process was still uncertain. Discussions with MISO staff and outside consultants convinced Morgan that the queue reform efforts were unlikely to succeed. In that event, Morgan believed that MISO would immediately terminate the LGIA after the suspension period ended. Morgan's valuable queue position would be lost and further development work would not be economically advisable. Fortunately, for

[13] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221(December 16, 2010), attached as Exhibit C.
[14] *Id*. at Para. 1.
[15] *Id*.

Morgan, the queue reform effort appears to be on the road to success and it makes sense for Morgan to continue its development efforts.

The FERC issued another order on March 23, 2012 that will significantly impact Morgan and all other projects in the interconnection queue.[16] This order is expected to reduce of the number of projects seeking to interconnect within the MISO footprint.[17] The FERC authorized MISO to change the M2 milestone payment, which is a threshold requirement under MISO's tariff for a project to move from the System Planning and Analysis phase of the interconnection process to the Definitive Planning Phase. In the past, projects were able to meet the M2 milestone through various means, including ordering turbines.[18] Now, projects must make a significant cash payment to MISO. That deposit will likely not be refundable, and most projects will be required to make the payment regardless of whether they have previously met the M2 milestone.[19]

MISO and the FERC expect that this requirement will dramatically reduce the number of projects in the queue. Morgan agrees. And Morgan expects that the reduction of total projects in the queue will, in turn, impact the cost allocation of the MVP projects and other upgrades required to interconnect Group 5 by reducing the overall load that MISO needs to accommodate on the transmission system. In theory, that may result in fewer required upgrades to the transmission system.

Prior to this order, a project had to either make progress and satisfy the M2 milestone requirement within a certain time period or drop out of the queue. MISO has now established what will effectively be a second queue by allowing a project to remain in the System Planning

[16] *Midwest Independent Transmission System Operator, Inc.*, 138 FERC ¶ 61,233 (March 30, 2012), attached as Exhibit D.
[17] *Id*. at Para. 30.
[18] *Id*. at Para. 13, 14.
[19] *Id*. at Para. 102, 104, 105, 107, 121, 146-156.

and Analysis phase as long as it refreshes its System Impact Study once every 18 months.[20] This creates additional safety for projects by allowing them to remain within the interconnection process.

Unlike many projects, Morgan has an executed LGIA with MISO. According to the FERC, projects with LGIA's may not be required to retroactively make the new M2 milestone payment.[21] Morgan, however, placed its executed LGIA in suspension, which ends soon. Morgan is currently studying its options and contacting MISO to develop a plan of action for when the LGIA suspension period ends. Options may include returning to the System Planning and Analysis phase, negotiating a new LGIA with MISO due to the changes in the queue over the past several years, or taking some other step.

Morgan is also awaiting the results of all studies for Group 5, which are still not complete. The latest estimate is that the Group 5 facilities study will be issued sometime in 2012.[22]

Once Morgan has evaluated its options with respect to the LGIA and knows the results of the Group 5 facilities study, it will still need to enter into an enforceable mechanism to sell its power, perform required pre-construction planning and report the results to the MPUC,[23] finalize construction agreements and complete other development tasks.

[20] *Id*. at Para. 108-110, 116
[21] *Id*. at Para. 105.
[22] *Id*. at Para. 67.
[23] Morgan understands that, among other tasks, it will be required at a minimum to demonstrate site control, perform a wake-loss study, demonstrate that required setbacks are met, perform a biological preservation survey, conduct an archaeological resources survey if required by the State Historical Preservation Office and the State Archaeologist, perform an assessment of potential electromagnetic interference and submit a decommissioning plan.

D. The MPUC Has Good Cause to Amend the Permit.

Morgan acknowledges that there are significant tasks left to be completed. Yet Morgan could not complete essential parts of the development process during the two-year period it had under the Permit. The MISO Group 5 studies and queue reform process filled and then overran that entire window of opportunity. Morgan acknowledges that the MPUC's imposition of a deadline to begin construction is sensible and reflects public policy that favors development of Minnesota's best wind resources. The deadline allows the MPUC to revoke a permit when a developer fails to make progress on a project, thereby allowing another developer to gain access to the site. That deadline, on the other hand, should not be used to end the Project's path to development under these circumstances. Revocation of the Permit would not help the MPUC meet its policy goals. But the interconnection process has caused delays that were both beyond Morgan's control and unanticipated by most wind developers or regulators. Any other developer would have had the same problem at this site.

The MPUC may amend the Permit to extend the deadlines upon a showing of good cause,[24] which is certainly present here. Public policy in Minnesota favors CBED facilities like the Project.[25] There is no dispute with participating landowners or neighbors, a business model problem or any other issue that would not be present with a different development team. Morgan's inability to make competitive bids for a PPA or start construction are direct results of the MISO interconnection and queue reform process.

Morgan did not just sit on the Permit during the two-year period. As discussed above, Morgan also worked diligently to obtain a PPA despite the cost uncertainty. Unfortunately, the bids Morgan submitted for the few PPA opportunities available during that time frame were not

[24] Minn. R. 7854.1300, subp. 2.
[25] Minn. Stat. § 216B.1612.

accepted. This should not be held against Morgan, which was forced to account for extremely high and very uncertain interconnection costs in its bid prices. The cost uncertainty also impacted Morgan's ability to find external financing. Morgan should soon know its cost to interconnect. At that time it should be able to make accurate bids, attract financing and complete development. Morgan's development work during that period also included:

- issuing a project update to landowners and lessors in January, 2011;
- paying deposits to MISO of $115,000 for other studies and expenses since December, 2008;
- paying an additional deposit of more than $40,000 to MISO for a new facilities study deposit in August, 2011;
- working with GRE and a lessor to develop a consent and crossing agreement for the Brookings Line to pass through the Project site;
- working with prospective partners to continue with the DPP process;
- maintaining two met towers through maintenance and repair;
- maintaining insurance policies;
- gathering and assessing wind data;
- working with outside consultants to assess impacts of MISO's tariff and queue reform efforts.

The MPUC faced similar circumstances for the Sibley and Comfrey wind projects. In those dockets, it determined that the deadlines to obtain a mechanism to sell power and commence construction should be amended. Morgan respectfully requests the same opportunity.

E. A two-year extension is appropriate.

Morgan still needs time to complete development tasks that depend on knowing the final development costs of the Project, including interconnection fees. These steps include waiting for the Group 5 facilities study to be completed sometime this year, and then entering into a power purchase agreement or finding another mechanism to power, completing negotiations with an equity investor, finalizing a turbine supply agreement, entering into a construction contract and performing pre-construction studies and surveys required by the Permit. The MISO process

alone will consume at least the remainder of 2012. Morgan therefore requests that the Permit be amended to allow two additional years to obtain a PPA and begin construction.

F. Notice can still be provided to landowners and the public.

Morgan regrets that notice was not properly sent after the Permit was issued. Morgan anticipates, however, that this petition will trigger a comment period, and that notice of the petition and comment period will be sent to the mailing list for the Project. Notice and an order will need to be sent again if the MPUC grants Morgan's request. That can be sent to all landowners. And an order amending the Permit will trigger a another reconsideration period. Any landowner that disagrees with the MPUC's decision will have the opportunity to respond and present arguments against the petition or for reconsideration. While this situation is not ideal, Morgan does have good relations with its landowners and neighbors. The Project did not generate excessive controversy at the time the Permit was issued, and Morgan does not believe that the situation has changed.

III. Conclusion

Morgan has been diligently working to develop the Project. The delays it has experienced were beyond its control, and good cause exists to allow Morgan to continue work on the Project following the completion of the MISO restudy process. Morgan respectfully requests that the MPUC grant Morgan the same opportunity that it has provided to other projects under these circumstances by extending the deadlines to enter into a power purchase agreement and begin construction by two years.

May 18, 2012

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Exhibit A

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EXHIBIT A

129 FERC ¶ 61,019
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER09-1581-000

ORDER CONDITIONALLY ACCEPTING AMENDED AND RESTATED GENERATOR INTERCONNECTION AGREEMENT

(Issued October 9, 2009)

1. On August 13, 2009, pursuant to section 205 of the Federal Power Act (FPA),[1] the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) submitted an unexecuted Amended and Restated Generator Interconnection Agreement (Amended GIA) among the Midwest ISO, Northern States Power Company (NSP), as transmission owner, and Community Wind North LLC (Community Wind) as interconnection customer (collectively, the Parties).[2] We accept the Amended GIA effective August 14, 2009, but we condition our acceptance on the Midwest ISO modifying the Amended GIA to remove any reference to cost responsibility for the Brookings County-Twin Cities 345 kV transmission line (Brookings Line).

I. Background

2. On December 9, 2008, the Parties executed a temporary interconnection agreement (Temporary GIA) involving Project No. G586, a 30 MW wind generation project consisting of twelve wind turbines that will each generate 2.5 MW (Generating Facility). The Temporary GIA provided for the limited operation of the Generating Facility prior to the completion of related interconnection studies pursuant to section 11.5 of the Midwest ISO's Generator Interconnection Procedures (GIP) in Attachment X of

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[1] 16 U.S.C. § 824d (2006).

[2] *Midwest Indep. Transmission Sys. Operator, Inc.*, Filing of Amended and Restated Generator Interconnection Agreement, Docket No. ER09-1581-000 (filed August 13, 2009) (Filing).

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the Midwest ISO Tariff.[3] Since the body of the Temporary GIA conformed to the *pro forma* GIA, the Temporary GIA was reported in the Midwest ISO's Electric Quarterly Report in accordance with Order No. 2003.[4]

3. Following completion of the related interconnection studies, Community Wind requested that the Temporary GIA be amended to include the updated study results. Despite extensive negotiations, the Parties have been unable to agree on revisions to the provisions of the appendices relating to Community Wind's responsibility for the costs of certain network upgrades. With negotiations at an impasse, Community Wind asked the Midwest ISO to file the Amended GIA unexecuted pursuant to section 11.3 of the GIP.

II. <u>The Filing</u>

4. The Midwest ISO requests that the Commission accept the Amended GIA, which provides for the interconnection of the Generating Facility at NSP's Yankee substation. The Midwest ISO states that the body of the Amended GIA conforms to the Midwest ISO's *pro forma* GIA that was in effect at the time that the Temporary GIA was executed, but that the appendices have been updated to provide cost estimates for network upgrades and contingencies that may affect Community Wind's cost responsibility.[5] The Midwest ISO requests that the Commission waive the 60 day prior notice of filing requirement and make the Amended GIA effective as of August 14, 2009 in order to provide certainty to the Parties as to the status of the agreement.

5. Under Appendix A of the Amended GIA, Community Wind agrees to share in the cost responsibility for the Shared Ownership Common Use upgrades, including the Brookings Line, which is a 230-mile, 345-kV transmission line that will connect Brookings County, South Dakota, with eastern Minnesota.[6] Section 2 explains that the Midwest ISO is in the process of developing a *pro forma* Multi-Party Facilities Construction Agreement (MPFCA) that will become an appendix to the Midwest ISO's

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[3] Midwest Independent Transmission System Operator, Inc., Open Access Transmission, Energy and Operating Reserve Markets Tariff, FERC Electric Tariff, Fourth Revised Volume No. 1, Appendix X (August 25, 2008) (Tariff).

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

[5] Filing, Transmittal Letter at 3.

[6] *Id.* at Original Sheet No. 91.

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tariff,[7] and that the MPFCA will set forth requirements for Community Wind and other Group 5 projects[8] to provide security and funding for the Shared Ownership Common Use Upgrades identified in Appendix A. Further, section 2(i) provides that the respective obligations of Community Wind and the affected Group 5 projects "to fund such . . . Shared Ownership Common Use Upgrades will . . . be the subject matter governed by" a future MPFCA.[9] The Amended GIA estimates that the total cost of the Brookings Line will be $700 million, and allocates the costs of the line to 19 Group 5 generators, including Community Wind. The Amended GIA estimates that Community Wind will be responsible for 2.5 percent of the total cost of the Brookings Line or $15 million.[10] However, Community Wind's responsibility for the cost of the Brookings Line is subject to: (1) the outcome of proposed revisions to Midwest ISO's regional cost sharing methodology that are pending before the Commission;[11] (2) whether any of the other 18

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[7] On August 21, 2009, in Docket No. ER09-1619-000, the Midwest ISO filed a proposal to revise its GIP to include a proposed *pro forma* MPFCA. According to the Midwest ISO, the MPFCA is designed to address situations where multiple interconnection customers cause the need and share the cost responsibility for common use upgrades to accommodate their interconnection requests. *Midwest Indep. Transmission Sys. Operator, Inc*., Electric Tariff Filing regarding Attachment X – Generator Interconnection Procedures, Docket No. ER09-1619-000, Transmittal Letter at 9 (filed August 21, 2009) (MPFCA Filing).

[8] The Group 5 projects consist of 32 individual interconnection requests totaling approximately 2,039 MW in Southwest Minnesota, Northwest Iowa, and Eastern South Dakota. The Midwest ISO's GIP in Attachment X provides that generator interconnection projects may be studied as a group for the purpose of conducting interconnection studies. The Midwest ISO conducted the generator interconnection system impact studies as a group for the Group 5 projects. The initial studies were performed in 2006 and 2007 and the study reports were posed during the summer and fall of 2007. As discussed below, the Amended GIA estimates that the costs of the Brookings Line will be funded by nineteen Group 5 projects, including Community Wind.

[9] Filing, Appendix A § 2(i).

[10] *Id.* Appendix A, Table 5.

[11] On July 9, 2009, the Midwest ISO filed proposed amendments to its tariff in Docket No. ER09-1431-000 to revise the method for allocating the cost of network upgrades for generation interconnection projects. Under the proposal, an interconnection customer would pay 90 percent of the cost of any network upgrades for facilities rates at or above 345 kV, such as the Brookings Line. *Midwest Indep. Transmission Sys. Operator, Inc*., Docket No. ER09-1431-000, at 15-16 (filed July 9, 2009) (Cost Allocation Filing).

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Group 5 projects assigned the costs of the Brookings Line drop out of the interconnection queue; and (3) any changes in the scope or funding of the Brookings Line.

6. The Midwest ISO states that Community Wind declined to execute the Amended GIA because of the inclusion of the language concerning Community Wind's responsibility for funding the Brookings Line.[12] The Midwest ISO states that Community Wind objects to the disputed language on the basis that the Brookings Line is not necessary to provide interconnection service for the Generating Facility and that the proposed language imposes a new obligation on Community Wind to pay an unknown cost.[13] According to the Midwest ISO, Community Wind asserts that inclusion of the proposed language makes it difficult to finance the project because developers and lenders are unable to bear the potential cost exposure of such a large upgrade.

7. The Midwest ISO argues that inclusion of the disputed provisions is appropriate, necessary, and consistent with Commission precedent. Citing Order Nos. 2003 and 2003-A, the Midwest ISO states that the Commission has recognized that each interconnection customer takes the business risk that its responsibility for funding network upgrades may change if certain contingencies occur, including the withdrawal of other interconnection customers, and that known contingencies for possible financial risk should be addressed in each interconnection agreement.[14] The Midwest ISO explains that the Brookings Line is properly included because it is a known contingency for Community Wind's interconnection project and others in the same group study. The Midwest ISO points out that the study results for the Group 5 projects have not yet resulted in agreements that allocate responsibility for the costs of the upgrades needed to accommodate the interconnection of the projects. The Midwest ISO also notes that Community Wind and other stakeholders are currently negotiating the terms and conditions of funding and constructing the Brookings Line. It anticipates that Community Wind will enter into a MPFCA with other generators to share in the costs of the line and that, if the negotiations are successful, the Midwest ISO anticipates amending the Amended GIA to reflect the resulting cost obligations. The Midwest ISO believes that the ongoing negotiations provide an efficient and effective means to resolve the matter.

8. The Midwest ISO also contends that the reference to the Brookings Line in the Midwest ISO Transmission Expansion Plan for 2008 (MTEP08) will not prevent Community Wind from having to share in the costs of the line. The Midwest ISO explains that the Brookings Line was included in MTEP08, and adds that the reference to

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[12] *See* Filing, Transmittal Letter at 4 n. 6.

[13] *Id.* Transmittal Letter at 4-5.

[14] *Id.* Transmittal Letter at 6.

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the Brookings Line in MTEP08 meant that the project had not yet been validated for possible designation as a Baseline Reliability Project[15] eligible for regional cost sharing under the Midwest ISO tariff.[16] According to the Midwest ISO, the reference to the Brookings Line in MTEP08 does not rule out the possibility that Community Wind will bear its share of the costs because the Brookings Line "is required primarily for the delivery of new wind energy resources, [and] is not a Baseline Reliability Project."[17]

III. Notice of Filing and Responsive Pleadings

9. Notice of the Midwest ISO's filing was published in the *Federal Register*, 74 FR 42893 (2009), with interventions and protests due on or before September 3, 2009. Community Wind, Otter Tail Power Company, Missouri River Energy Services, and Renewable Energy Systems America, Inc., filed motions to intervene. Buffalo Ridge Power, LLC (Buffalo Ridge), Iberdrola Renewables, Inc. (Iberdrola), Great River Energy (Great River), Xcel Energy Services (Xcel), Wind Capital Group, LLC (Wind Capital), the American Wind Energy Association and Wind on the Wires (together, AWEA and WOW), Edison Mission Energy (Edison), on behalf of Community Wind, and NextEra, on behalf of its operating subsidiary Story Wind LLC (Story Wind), filed timely motions to intervene and comments.

10. On September 18, 2009, the Midwest ISO, Xcel, and Great River each filed a motion for leave to answer and answer to the comments submitted in the proceeding. On September 29, 2009, Edison filed a motion for leave to answer and answer.

11. Several protesters argue that the Commission should reject the proposed cost allocation of the Brookings Line and order the Midwest ISO to modify the Amended GIA to remove any reference to the responsibility of Community Wind and other Group 5 projects for the costs of the line.[18] More specifically, Buffalo Ridge states that the proposed cost allocation subverts Order No. 2003 by holding Group 5 projects responsible for a network upgrade that is not necessary for their interconnection and that the Midwest ISO has provided no evidence that the Group 5 projects benefit from the

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[15] Baseline Reliability Projects are eligible for regional cost sharing and are designated by the Midwest ISO after meeting specified criteria.

[16] Filing, Transmittal Letter at 4 n. 6.

[17] *Id.* Transmittal Letter at 7 (citing MTEP08 at 7).

[18] Edison Protest at 1, 27; NextEra Protest at 12; Buffalo Ridge Protest at 3, 15; AWEA and WOW Protest at 12.

facility to an extent that warrants them bearing such costs.[19] Similarly, AWEA and WOW argue that the proposed allocation of costs does not represent a reasonable balance between cost causers and beneficiaries, and express concern that the Midwest ISO is attempting to thrust unidentified costs onto interconnection customers through an unexecuted agreement with just one of those customers.[20] Edison, NextEra, AWEA and WOW argue that generators may only be allocated the costs for upgrades that would not have been made but for their interconnection.[21]

12. Edison, NextEra,[22] AWEA and WOW state that the Brookings Line is being developed as part of the CapX2020 initiative, which is designed to support the growing demand for electricity in Minnesota and the surrounding region.[23] They point out that the Minnesota Public Utilities Commission initially imposed a number of conditions on the Brookings Line when granting the required certificate of need, but modified those restrictions on reconsideration because it recognized that the line will promote regional

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[19] Buffalo Ridge Protest at 5, 9-11 (citing *Illinois Commerce Commission v. FERC*, 2009 U.S. App. LEXIS 18311 at 13-14 (7th Cir. 2009) (stating that "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members").

[20] AWEA and WOW Protest at 7, 11-12.

[21] Edison Protest at 15 (citing *New York Indep. Sys. Operator, Inc.*, 97 FERC ¶ 61,113, at 61,573 (2001) (*NYISO*)); AWEA and WOW Protest at 8-10; NextEra Protest at 13-14.

[22] In addition, NextEra argues that the Midwest ISO has failed to meet its obligations under Order No. 2003-A. NextEra argues that Order No. 2003-A requires the Midwest ISO to provide an estimate of the costs of any network upgrades that were assumed in the interconnection studies for the interconnection customer that are an obligation of an entity other than the interconnection customer and that have not been constructed. Directing the Commission to the interconnection agreement between Story Wind, ITC Midwest LLC and the Midwest ISO, NextEra notes that, despite the fact that the Amended GIA estimates that Story Wind will be required to pay $39.2 million or 5.61 percent of the total cost of the Brookings Line, the Midwest ISO did not include an estimate of the costs of such network upgrades in Story Wind's interconnection agreement. NextEra Protest at 23-24.

[23] Edison Protest at 21; AWEA and WOW Protest at 10; NextEra Protest at 13; Buffalo Ridge Protest at 7. CapX2020 is an initiative of eleven transmission-owning utilities in the Minnesota region, including Xcel and Great River Energy, to expand the transmission grid to meet increasing demand and to support renewable energy expansion by building four new transmission lines, including the Brookings Line.

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and community reliability.[24] Edison notes that a study done by an engineer retained by several of the Group 5 projects reveals that the reliability concerns arising from the interconnection of the projects could be addressed by either adding shunt capacitors at strategic locations for $18.8 million or installing a shorter transmission line for $166.4 million.[25] Edison states that under Commission precedent the Midwest ISO can only require Community Wind to fund its proportionate share of the least cost alternative, which only costs $18.8 million. Edison urges the Commission to: (1) direct the Midwest ISO to revise the Amended GIA to substitute Community Wind's responsibility for the line with its share of the lowest cost alternative; (2) direct Midwest ISO to re-study the Group 5 projects in 30 days, taking the alternatives into consideration, and revise the Amended GIA accordingly; or (3) set the Amended GIA for hearing and settlement judge procedures.[26] Iberdrola makes a similar request and asks the Commission to appoint a settlement judge to initiate settlement procedures to determine the appropriate allocation of costs associated with the line.[27]

13. Xcel and the Midwest ISO argue that the Amended GIA merely provides an estimate of Community Wind's responsibility for the costs of the Brookings Line, which is required by Order No. 2003-A.[28] Great River maintains that providing a greater degree of certainty is unnecessary and impractical.[29] Great River, Xcel, and the Midwest ISO argue that litigating allocation of the costs of the Brookings Line in this proceeding could have an adverse effect on ongoing stakeholder negotiations and would implicate issues that go beyond the scope of the Amended GIA.[30]

14. Xcel argues that the alternative study Edison mentions does not provide an appropriate basis for cost allocation because: (1) it would be inconsistent with coordinated regional planning for NSP to construct both the alternatives advocated by the study and the Brookings Line; and (2) the study is flawed because it is only oriented toward resolving stability limitations, ignores thermal limitations, and assumes the

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[24] Edison Protest at 20 (citing *In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects*, Order Granting And Denying Motions For Reconsideration, And Modifying Conditions, Docket No. ET-2, E-002, at 12 (August 10, 2009)).

[25] *Id.* at 26.

[26] *Id*. at 28.

[27] Iberdrola Protest at 1, 7.

[28] Xcel Initial Comments at 10; Midwest ISO Answer at 6.

[29] Great River Comments at 4-7.

[30] Great River Answer at 6; Xcel Answer at 7-8; Midwest ISO Answer at 6-8.

existence of a transmission line, the Storden Line, that is no longer planned and two 30 MVAR capacitors that were never installed.[31] Xcel states that the CapX2020 utilities have not changed their view of the Brookings Line or asked the Midwest ISO to change the proposed treatment of the line.[32] Xcel states that the utilities believe that the Brookings Line should be treated as a Baseline Reliability Project because it is designed to serve multiple needs beyond the interconnection of particular generators.[33] Xcel states that while the Midwest ISO has the power to classify the project as it has done,[34] NSP is not inclined to assign all, or even most, of the costs of the Brookings Line to the Group 5 projects.[35]

15. In response, Edison argues that Xcel's admission that the Brookings Line is designed to serve multiple needs demonstrates that the Brookings Line is not necessary for the interconnection of Community Wind.[36] Edison argues that Xcel's claim that the alternative study is inconsistent with regional planning confuses the regional planning process with the generator interconnection process. Edison also asserts that it is not suggesting that NSP should build both the Brookings Line and the alternative upgrades, but that Community Wind can only be held responsible for its proportionate share of the lowest cost alternative if the Brookings Line is built.[37] Edison notes that the alternative study only addressed stability limitations because the Midwest ISO has indicated that the Brookings Line is only designed to remedy stability limitations.[38] In addition, Edison

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[31] Xcel Answer at 10-11.

[32] *Id.* at 4-5.

[33] Xcel states that the allocation of the costs of the Brookings Line shows the limitations of the MTEP process and the current method of allocating costs in the Midwest ISO. Xcel states that it supports the creation of a new permanent regional expansion criterion and benefits cost allocation method that accounts for the need of vertically integrated utilities to recover new investment in transmission facilities. Xcel Initial Comments at 11-13.

[34] Xcel Answer at 5-7; Xcel Initial Comments at 11 (citing *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, 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 (2009)).

[35] Xcel Answer at 11.

[36] Edison Answer at 4-5.

[37] *Id.* at 4-6.

[38] *Id.* at 6-7.

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points out that no final decision has been made about the Storden Line and that the study did not assume that the capacitors were installed but, instead, proposed to install them.[39]

16. Xcel urges the Commission to defer acceptance of the provisions assigning responsibility for the costs of network upgrades until the Commission makes a determination regarding the Midwest ISO's proposal to modify its generation interconnection cost allocation methodology in Docket ER09-1431-000. Xcel argues that the Commission should also defer action on the reasonableness of the obligation to execute a MPFCA until the Commission makes a determination on the tariff changes proposed in Docket No. ER09-1619-000, including the *pro forma* MPFCA.[40] Xcel also recommends that the Commission defer action on the Amended GIA for five months to allow time for the various stakeholder processes to reach a resolution and require the Midwest ISO to report on the progress of stakeholder discussions 60 and 120 days after the initial Commission order. Xcel states that the Commission can institute hearing and settlement procedures if the negotiations have not made sufficient progress at that time.[41] In addition, Xcel asks the Commission to order the Midwest ISO to defer filing of other Group 5 generator interconnection agreements that are pending execution or are going to be filed on an unexecuted basis because failure to do so would cause all affected parties to incur substantial and unnecessary costs.[42]

17. Edison argues that the Commission should not defer action on the Amended GIA for two reasons. First, Edison contends that the proceedings and negotiations that Xcel identified do not address the network upgrades Community Wind should be responsible for under the Amended GIA, which is the central issue in dispute in this proceeding.[43] Second, only by promptly directing the Midwest ISO to remove cost responsibility for the Brookings Line or to re-study the Community Wind project can the Commission avoid further delays and possible abandonment of the Community Wind project.[44]

18. A number of protesters argue that the costs of the Brookings Line should be allocated regionally. Edison argues that the Midwest ISO has the option of expanding the

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[39] *Id.* at 8-9.

[40] Xcel Initial Comments at 10.

[41] Xcel Answer at 9.

[42] *Id.* at 12.

[43] Edison Answer at 4, 9-11. Edison asserts that the ongoing discussions about the Brookings Line will not progress until the Commission rejects the proposed allocation of the costs of the Brookings Line.

[44] *Id.* at 12-13.

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definition of a Baseline Reliability Project to include the Brookings Line.[45] NextEra, AWEA and WOW argue that the Brookings Line should be classified as a Baseline Reliability Project, Regionally Beneficial Project, or Other Project.[46] Buffalo Ridge simply argues that the costs of the Brookings Line should be rolled-in on a regional or system-wide basis.[47] On the other hand, Great River argues that the Commission would be ignoring the clear provisions of Attachment FF if it ordered the Midwest ISO to classify the project as requested by the protesters.[48]

19. Several protesters also argue that the Amended GIA is unreasonable because it subjects Community Wind and other Group 5 projects to a large, open-ended, and unreasonable contingent cost obligation.[49] They argue that the Amended GIA threatens to halt development of wind generation in the region by placing the entire cost of the Brookings Line on Community Wind and other Group 5 projects. Edison argues that the Commission should limit Community Wind's cost responsibility to the estimated cost of network upgrades in the Amended GIA.[50]

IV. Discussion

A. Procedural Matters

20. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2009), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

21. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2009), prohibits answers unless otherwise ordered by the decisional authority. We will accept the answers of the Midwest ISO, Xcel, Great River and Edison because they assisted us in our decision-making process.

B. Substantive Matters

22. We conditionally accept the Amended GIA, subject to the Midwest ISO revising the agreement, as discussed below. We also find good cause exists to grant the Midwest

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[45] Edison Protest at 29.

[46] NextEra Protest at 3; AWEA and WOW Protest at 10.

[47] Buffalo Ridge Protest at 13.

[48] Great River Answer at 3-4.

[49] Edison Protest at 30-32, 34-38; Wind Capital Comments at 2-3.

[50] Edison Protest at 33-34.

ISO's request for waiver of the 60-day prior notice requirement to permit an effective date of August 14, 2009, one day after the filing.[51]

23. Under the Midwest ISO's tariff, interconnection customers may only be required to fund the costs of network upgrades that are necessary for their interconnection. The Midwest ISO's tariff uses the "but for" standard for the purpose of allocating the cost of network upgrades.[52] Under that standard, "generation developers are to be allocated the costs for transmission system upgrades that would not have been made but for the interconnection of the developers, minus the cost of any facilities that the ISO's regional plan dictates would have been necessary anyway for load growth and reliability purposes."[53] In other words, under the Midwest ISO's tariff, a generator can only be allocated the cost of network upgrades that would not have been constructed but for the interconnection of the generator.[54]

24. The Midwest ISO attempts to require Community Wind to share in the costs of the Brookings Line with other generator interconnection customers on the basis that an interconnection customer must fund the cost of all network upgrades needed to support that customer's in-service date.[55] The Midwest ISO asserts, without supporting its conclusion, that the Brookings Line is "required primarily for the delivery of new wind energy resources."[56] Under the Amended GIA, the Midwest ISO allocates the cost of the

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[51] *See Central Hudson Gas & Electric Corp.*, 60 FERC ¶ 61,106 (1992).

[52] The Midwest ISO has adopted the language of the *pro forma* LGIA adopted in Order No. 2003. *Compare* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, Appendix C § 1 (defining network upgrades as "the additions, modifications, and upgrades to the Transmission Provider's Transmission System *required* at or beyond the point at which the Interconnection Customer interconnects to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System" (emphasis added)), *with* Tariff, Attachment X § 1 (defining network upgrades as the "additions, modifications, and upgrades to the Transmission System *required* at or beyond the point at which the Interconnection Facilities connect to the Transmission System or Distribution System, as applicable, to accommodate the interconnection of the Generating Facility to the Transmission System" (emphasis added)). *See also, id.* § 8.4 (stating that the Interconnection Facilities Study must specify and estimate the cost of the *required* equipment and construction work needed to physically and electrically connect the Interconnection Facilities to the Transmission System (emphasis added)).

[53] *NYISO*, 97 FERC at 61,573.

[54] Tariff, Appendix FF § III.A.2.d.3(b).

[55] Filing, Transmittal Letter at 6 (citing Order No 2003-A, ¶ 31,160 at P 320).

[56] *Id.* at 7.

Brookings Line to Community Wind and 18 other Group 5 projects without the Midwest ISO providing any evidence that the Brookings Line would not have been built but for the interconnection of these generation projects. The Commission finds that, based on the information that the Midwest ISO has provided in this docket, the allocation of the costs of the Brookings Line to Community Wind has not been shown to be just and reasonable, and must be rejected. We reject the Midwest ISO's proposal without prejudice to the Midwest ISO re-filing a proposal to allocate the costs of the Brookings line with appropriate support.

25. We will deny the requests of several protesters to set the Amended GIA for hearing or settlement judge procedures. The Midwest ISO has provided no evidence that the Brookings Line would not be constructed but for the interconnection of Community Wind and other Group 5 projects. Therefore, setting the Amended GIA for hearing and settlement procedures is unnecessary.

26. The Commission rejects the argument that it should defer action on the Amended GIA for the Community Wind project pending the outcome of other Commission proceedings and ongoing stakeholder discussions for two reasons. First, the outcome of the proceedings identified by Xcel will not address the issue of whether the costs of the Brookings Line can be allocated to Community Wind or other Group 5 projects. In Docket No. ER09-1431-000, the Midwest ISO has proposed changes to the method that it uses to allocate the costs of network upgrades. Under the current Midwest ISO tariff, interconnection customers are required to pay the entire cost of network upgrades upfront. If, after achieving commercial operation, the interconnection customer designates its facility as a network resource or enters into a contract with a term of at least one year to supply capacity or energy to a network customer, then 50 percent of the costs of network upgrades will be repaid to the interconnection customer.[57] Under the Midwest ISO's proposal, the interconnection customer will be repaid 10 percent of the costs once commercial operation has been achieved, rather than 50 percent of such costs.[58] Thus, while the proceedings in Docket No. ER09-1431-000 may impact Community Wind's eligibility for reimbursement of the costs of network upgrades, the proceedings do not address whether Community Wind can be required to fund the costs of the Brookings Line in the first place.

27. Likewise, the Midwest ISO's proposed revisions to its GIP in Docket No. ER09-1619-000 does not address the question of whether Community Wind can be obligated to share in the costs of the Brookings Line. In that proceeding, the Midwest ISO has proposed to revise its GIP to include two new *pro forma* agreements: (1) a facilities construction agreement for a single interconnection customer; and (2) a MPFCA to

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[57] Tariff, Attachment FF, section III.A.2.d.

[58] Cost Allocation Filing, Transmittal Letter at 15.

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address the situation where multiple interconnection customers cause the need and share the cost responsibility for common use upgrades to accommodate their interconnection requests.[59] While that proceeding may impact any MPFCA that Community Wind and the other affected stakeholders ultimately enter into relating to the Brookings Line, those *pro forma* agreements are not relevant to the disposition of this case.

28. Second, deferring action on the agreement, as Xcel requests, pending the outcome of the ongoing stakeholder negotiations for the MPFCA is unnecessary. As the Midwest ISO has failed to meet its burden in demonstrating that the provisions of the Amended GIA relating to the Brookings Line are just and reasonable, we must reject the provisions of the Amended GIA relating to the Brookings Line and this order does not foreclose further discussions.

29. Accordingly, we will accept the filing, subject to the Midwest ISO making a compliance filing within 30 days to remove the unsupported language relating to any cost responsibility of Community Wind or other Group 5 projects for the costs of the Brookings Line.

The Commission orders:

(A) The Amended GIA is hereby accepted as conditioned in the body of the order, to become effective August 14, 2009, as requested.

(B) The Midwest ISO is required to make a compliance filing within 30 days of the date of this order, as discussed in the body of the order.

By the Commission. Commissioner Kelly concurring in part and dissenting in part with a separate statement to be issued at a later date.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[59] MPFCA Filing, Transmittal Letter at 5.

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131 FERC ¶ 61,165
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
and John R. Norris.

Midwest Independent Transmission System Operator, Inc.	Docket Nos. ER09-1581-001 ER09-1581-003

ORDER ON REHEARING AND COMPLIANCE FILING

(Issued May 20, 2010)

1. On October 9, 2009, the Commission conditionally accepted an Amended and Restated Generator Interconnection Agreement (Amended GIA) among Midwest Independent Transmission System Operator, Inc. (Midwest ISO), Northern States Power Company (Northern States), as transmission owner, and Community Wind North LLC (Community Wind) as interconnection customer (together, the Parties).[1] The Commission required Midwest ISO to modify the Amended GIA to remove unsupported language relating to Community Wind's responsibility for the costs of a particular network upgrade, the Brookings County-Twin Cities transmission line (Brookings Line).[2]

2. In this order, the Commission addresses requests for rehearing and clarification of the Initial Order as well as a compliance filing required by the Initial Order (Compliance Filing).[3] As set out below, we will deny requests for rehearing of the Initial Order, grant clarification, and require Midwest ISO to further revise the Amended GIA. Specifically we clarify that the Initial Order's direction to remove any reference to the Brookings Line was based upon a concern that the degree of cost allocation, i.e., based on 100 percent

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[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,019 (2009) (Initial Order).

[2] The Brookings Line is a 230-mile, 345-kV transmission line that will connect Brookings County, South Dakota, with eastern Minnesota.

[3] Midwest Indep. Transmission Sys. Operator, Inc., Compliance Filing, Docket No. ER09-1581-003 (Filed November 9, 2009).

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cost allocation to generator interconnection, was unsupported. This order finds that that degree of proposed cost allocation is still unsupported. We further clarify that the Initial Order's finding that the "but for" standard was not met was intended to address only the issue of determining cost responsibility and not whether a particular facility is built. Based on this clarification, we will dismiss the Compliance Filing and require a further compliance filing, as discussed below.

I. Background

3. On December 9, 2008, the Parties executed a temporary interconnection agreement (Temporary GIA) for Community Wind's 30 MW wind generation project (Generating Facility). The Temporary GIA provided for the limited operation of the Generating Facility prior to the completion of related interconnection studies pursuant to section 11.5 of the Midwest ISO's Generator Interconnection Procedures in Attachment X of the Midwest ISO Tariff.[4] Since the body of the Temporary GIA conformed to the *pro forma* GIA, the Temporary GIA was reported in Midwest ISO's Electric Quarterly Report in accordance with Order No. 2003.[5]

4. Following completion of the related interconnection studies, Community Wind requested that the Temporary GIA be amended to include the updated study results. Despite extensive negotiations, the Parties could not agree on revisions to the provisions of the appendices relating to Community Wind's responsibility for the costs of the Brookings Line. Community Wind therefore asked Midwest ISO to file the Amended GIA unexecuted pursuant to section 11.3 of the Generator Interconnection Procedures.

5. In the Initial Order, the Commission found that Midwest ISO had not shown that allocation of the costs of the Brookings Line to Community Wind was just and reasonable. The Commission found that Midwest ISO's Tariff uses the "but for" standard for the purpose of allocating the cost of network upgrades, and that, under that standard, an interconnection customer can only be allocated the cost of network upgrades

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[4] Midwest Independent Transmission System Operator, Inc., Open Access Transmission, Energy and Operating Reserve Markets Tariff, FERC Electric Tariff, Fourth Revised Volume No. 1, Appendix X (August 25, 2008) (Tariff).

[5] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 915 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

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that would not have been constructed but for the interconnection of the generator.[6] Midwest ISO had failed to provide any evidence that the Brookings Line would not be constructed but for the interconnection of Community Wind and other projects within its study group, the Group 5 projects,[7] and so the Commission directed Midwest ISO to revise the Amended GIA to remove unsupported language relating to any responsibility of Community Wind or the Group 5 projects for the costs of the Brookings Line.[8]

6. Midwest ISO filed the Compliance Filing, as required, on November 9, 2009. The Compliance Filing includes a revised Amended GIA, which, Midwest ISO asserts, complies with the Initial Order. The Compliance Filing also includes revisions to the Amended GIA that return it to the status of a temporary (or provisional)[9] GIA that will be subject to operating limitations until further studies have been completed.

II. Notice of Filing and Responsive Pleadings

7. Several parties filed motions for rehearing or clarification, including Great River Energy (Great River), Midwest ISO, and Xcel Energy Services Inc. (Xcel), on behalf of Northern States. Edison Mission Energy (Edison) filed a motion for clarification or rehearing and a motion for expedited treatment. Both Xcel and Midwest ISO submitted motions for leave to answer and answers to Edison's request for rehearing.

8. Notice of the Compliance Filing was published in the *Federal Register*, 74 Fed. Reg. 61,342 (2009), with interventions and protests due on or before November 30, 2009. Edison filed a timely protest, combined with a motion for leave to answer and answers to Midwest ISO's and Xcel's answers to the rehearing requests. Midwest ISO filed an answer to Edison's protest, and Edison filed an answer to Midwest ISO's answer.

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[6] Initial Order, 129 FERC ¶ 61,019 at P 23.

[7] Under the Midwest ISO Generator Interconnection Procedures, generator interconnection projects may be grouped together for the purpose of conducting interconnection studies. The Midwest ISO followed this procedure for the Group 5 projects, which request interconnection in southwest Minnesota, northwest Iowa, and eastern South Dakota. The initial studies were performed in 2006 and 2007 and the study reports were posted during the summer and fall of 2007.

[8] Initial Order, 129 FERC ¶ 61,019 at P 29.

[9] The Tariff was recently amended, and now refers to temporary GIAs as provisional GIAs. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,301 (2009).

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III. Discussion

A. Procedural Matters

9. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2009), prohibits answers to rehearing requests. We will therefore reject the answers of Xcel, Midwest ISO, and Edison.

10. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2009), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We are not persuaded to accept the answers of Midwest ISO or Edison and will, therefore, reject them.

B. Substantive Matters

1. Requests for Rehearing

a. Support for the Brookings Line

i. Rehearing Requests

11. In its rehearing request, Midwest ISO argues that, by finding no evidence in support of allocating the costs of the Brookings Line to the Group 5 projects, the Commission failed to examine the relevant data in the record. It also contends that the Commission failed to articulate why the data, along with publicly-available studies, did not provide appropriate support for the inclusion of the Brookings Line in the Amended GIA.[10]

12. Midwest ISO also argues that the Commission failed to articulate a rational connection between the facts and the decision to reject the use of the Brookings Line.[11] It states that several interveners, as well as a study Edison submitted in the underlying proceeding, acknowledge that the interconnection of the Group 5 projects will result in stability issues.[12] Midwest ISO adds that the Brookings Line is not merely a solution to these stability issues, but that it has been subjected to extensive study and peer review.[13]

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[10] Midwest ISO Request for Rehearing at 26-28.

[11] *Id.* at 27.

[12] *Id.* at 29.

[13] *Id.* at 30-31. Midwest ISO asserts that other solutions to resolve the impact of the Group 5 projects would need to be planned and studied, and may restart the state

(continued…)

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It argues that the Commission erred to the extent that it based its finding on Edison's study, as the study is flawed and Midwest ISO is not required to accept customer studies.[14] While Midwest ISO acknowledges that the Brookings Line provides benefits to the transmission system aside from the inclusion of more generation, Midwest ISO asserts that the interconnection of new generation facilities drives the need for the 345 kV facility.[15]

13. Midwest ISO also seeks rehearing or clarification that the "but for" standard should apply on a group basis for projects studied under the group study process. It argues that the Initial Order is unclear about whether the "but for" standard requires a determination that a specific network upgrade is the least-cost upgrade that would not have been built but for the interconnection of a single project, as Community Wind suggests. Midwest ISO contends that to consider each project in a group study to be responsible for only an individualized cost assessment would undercut the theory behind group studies for efficient planning. It asks the Commission to reverse or clarify the Initial Order to the extent that the Initial Order would permit a single interconnection customer to divorce itself from the group study results based on the claim that it was not accurately represented by the group.

14. Midwest ISO next requests rehearing or clarification that its discretion to determine that the upgrades required to accommodate interconnection requests is not limited to bare minimum upgrades under the "but for" standard. It contends that the Initial Order's application of the "but for" standard appears to exclude Midwest ISO's planning process and the application of Good Utility Practice, and to limit Midwest ISO's discretion regarding cost allocation to upgrades that would not have been made "but for the interconnection of the developers, minus the costs of any facilities that the ISO's regional plan dictates would have been necessary anyway for load growth and reliability purposes."[16] Midwest ISO argues that the language of section 8.4 of the Generator Interconnection Procedures clarifies that what equipment is required for the interconnection of a project or group of projects is based on the Midwest ISO study process and Good Utility Practice; therefore, Midwest ISO is only required to find a reasonable solution for interconnecting the entire set of Group 5 projects. According to

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certification process, and that the consideration of an existing, vetted solution, is consistent with Good Utility Practice.

[14] *Id.* at 31-34 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 124 FERC ¶ 61,183, at P 167-168 (2008) (Queue Reform Order)).

[15] Midwest ISO Request for Rehearing at 31.

[16] *Id.* at 38-39 (quoting Initial Order, 129 FERC ¶ 61,019 at P 23).

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Midwest ISO, the Commission misapplied the "but for" standard to place a burden on Midwest ISO to justify the outcome of its study and planning process because the Commission found no evidence to meet the "but for" standard.[17]

15. Midwest ISO contends that the Brookings Line was identified as a network upgrade necessary to resolve a system impact caused by a subset of constituents of Group 5, which include Community Wind. It contends that removing the contingency from the Amended GIA for Community Wind's project arbitrarily singles out one agreement from among the Group 5 projects, and would void the study results that Midwest ISO relied on to update the appendices of the Amended GIA. This, Midwest ISO argues, departs from the Commission's directive in Order Nos. 2003 and 2003-A to include such costs in the appendices of GIAs.[18]

16. Midwest ISO asserts that the Initial Order violates the requirements of Order No. 2003 by failing to address Midwest ISO's contention that the contingency risk described in Appendix A of the Amended GIA is the same risk shared by other similarly situated generator interconnection projects and that including these contingencies in the Amended GIA is consistent with the Commission's guidance in Order No. 2003. Midwest ISO maintains that the Initial Order erroneously required it to remove the known contingency of the unbuilt Brookings Line, which was shown to be necessary for this project to interconnect and receive interconnection service without limitation.[19] Moreover, Midwest ISO asks the Commission to clarify that the Initial Order did not alter the standards articulated in Order No. 2003 to require additional justification for cost estimates in GIAs as standard practice.[20]

ii. <u>Commission Determination</u>

17. The Initial Order's primary concern was that the Amended GIA's allocation of the costs of the Brookings Line to Community Wind was not supported by record evidence. As noted in the Initial Order, Appendix A of the Amended GIA provided that

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[17] Midwest ISO Request for Rehearing at 40-44. Midwest ISO argues that its Generator Interconnection Procedures represent an independent entity variation and that the Commission erred to the extent it failed to consider Midwest ISO's variation in the Tariff. *Id.* at 41 & n.107.

[18] *Id.* at 20-21.

[19] *Id.* at 16-17 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 409; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 320).

[20] Midwest ISO Request for Rehearing at 34-37.

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Community Wind shares in the cost responsibility for the Brookings Line and included a table estimating that 100 percent of the total cost of the Brookings Line would be allocated to a subset of the Group 5 projects, including Community Wind.[21] In support of its proposed cost allocation, Midwest ISO argued that the Brookings Line is a known contingency for Community Wind and that the reference to the Brookings Line in the Midwest ISO Transmission Expansion Plan 2008 does not preclude Community Wind from bearing its share of the costs because the Brookings Line is required primarily for the delivery of new wind energy resources and is not a Baseline Reliability Project.[22] Yet, despite Midwest ISO's assertions, the evidence in the record demonstrated that the Brookings Line was developed as part of the CapX2020 Initiative to serve multiple needs beyond the interconnection of particular generators.[23] Further, while studies identified by several protesters, and in Midwest ISO's request for rehearing, demonstrated that certain stability problems arising from the interconnection of the Group 5 projects disappear once the Brookings Line is in service, the evidence also demonstrated that the Brookings Line had been assumed in the base case covering the out-year horizon – something that further suggested that the Brookings Line was needed for more than interconnection purposes.[24]

18. Accordingly, the Commission rejected Midwest ISO's proposed cost allocation, finding that "based on the information that the Midwest ISO has provided in this docket, the allocation of the costs of the Brookings Line to Community Wind has not been shown to be just and reasonable . . . ."[25] The Commission concluded only that the evidence in

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[21] Initial Order, 129 FERC ¶ 61,019 at P 5.

[22] *Id.* at P 8; Filing, Transmittal Letter at 5-9. As discussed further below, Midwest ISO's characterization of the Brookings Line as a known contingency for Community Wind is inconsistent with some of the language of Appendix A.

[23] *See, e.g.*, Xcel Comments, Docket No. ER09-1581-000, at 12 (filed Sept. 3, 2009); Xcel Answer, Docket No. ER09-1581-000, at 4-5 (filed Sept. 18, 2009).

[24] *See e.g.*, Edison Protest, Docket No. ER09-1581-000, at 3 (filed Sept. 3, 2009); Midwest ISO Request for Rehearing at 9; NextEra Protest, Docket No. ER09-1581-000, at 2 (filed Sept. 3, 2009); Buffalo Ridge Power Partners, LLC Protest, Docket No. ER09-1581-000, at 25 (filed Sept. 3, 2009). As we noted in Order No. 2003-A, "the Commission has made exceptions to its policy of prohibiting the direct assignment of Network Upgrade costs in cases where the Transmission Provider is *independent* of market participants." Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 587 (emphasis added).

[25] We clarify that the Initial Order does not modify the standards articulated in Order No. 2003 to require additional justification for cost estimates in GIAs as standard

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the record did not support Midwest ISO's proposal to allocate the costs of the Brookings Line as a network upgrade; it made no finding regarding the effectiveness of the Brookings Line in resolving the stability issues and permitting interconnection service for the Group 5 projects. Thus, we reject Midwest ISO's argument that the Commission failed to examine relevant data and articulate a rational connection between the facts found and its decision in the Initial Order, and deny rehearing of the Initial Order in this regard.

19. We agree with Midwest ISO that the Initial Order could be read to suggest that the "but for" standard must be used to determine the upgrade that is constructed to facilitate a new interconnection. The Initial Order recited the "but for" standard as it is stated for a single generator,[26] but then required Midwest ISO "to remove the unsupported language

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practice. On the contrary, the Initial Order rejected the Amended GIA on the basis that Midwest ISO had failed to meet its burden under section 205 of the FPA. *See e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,054, at P 37 (2009) (noting that the filing party has the burden of demonstrating a rate is just and reasonable in the first instance).

[26] Initial Order, 129 FERC ¶ 61,019 at P 23 ("In other words, under the Midwest ISO's tariff, a generator can only be allocated the cost of network upgrades that would not have been constructed but for the interconnection of the generator."). We clarify that the Initial Order was not meant to suggest that the "but for" standard should be applied to each individual project when studied as part of a reasonably constituted group; for example, where, as here, projects are grouped on the basis of a combination of queue position and electrical proximity. *See* Tariff, Attachment X at section 4.2, First Revised Sheet No. 3074. The Initial Order did not require separate treatment for Community Wind apart from the other Group 5 projects. Moreover, we note that section 4.1 of Midwest ISO's Generator Interconnection Procedures provides that, in the case of group studies, "the determination of cost responsibility for common facilities necessary to accommodate two or more Interconnection Requests . . . may depend on factors other than Queue Position." This tariff language reflects the Commission's finding in Order No. 2003-A that the "but for" standard applies on a group basis for projects studied as a group. *See* Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 120. As the Commission recognized in Order No. 2003-A, where projects are studied as a group, the cost responsibility of an individual project may be greater than if it were studied individually. *Id.* ("Sometimes, one generating facility interconnecting alone would not require a substantial upgrade to the Transmission System, but when clustered with others, a costly upgrade may be required."). On the other hand, it is also possible that the use of group studies will result in cost savings for a customer and that the cost responsibility of

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relating to any cost responsibility of Community Wind *or other Group 5 projects* for the costs of the Brookings Line."[27] Combined, this order language could be read to mean that the "but for" standard requires that the need for the Brookings Line must be ascribed in its entirety to the Group 5 projects (and by extension, Community Wind), before any cost responsibility could be assigned. This was not the intent.

20. We clarify that we view the "but for" standard, in the context of Midwest ISO's Tariff, as a cost allocation principle that limits the cost responsibility of an interconnection customer or a group of interconnection customers to the cost of the upgrades that would not be necessary but for the interconnection of the customer or reasonably constituted group of customers. The Tariff adopts the language of the *pro forma* Large Generator Interconnection Agreement's (LGIA) definition of network upgrades and, like the *pro forma* LGIA, uses the "but for" standard. While Midwest ISO is correct in stating that it can propose variations from the Commission's *pro forma* LGIP as an independent Transmission Provider, we disagree with Midwest ISO's interpretation of section 8.4. To the extent that Midwest ISO suggests that the presence of the terms "System Planning and Analysis Review" and "Good Utility Practice" mean that the word "required" as it is used in section 8.4 and in the definition of network upgrades should be interpreted such that Midwest ISO's Tariff does not include the "but for" standard, we disagree. We note that in the very same proceeding that Midwest ISO proposed and the Commission accepted the addition of the term "required" to the "Scope of Interconnection Facilities Study" section (then section 8.2), Midwest ISO acknowledged that it was adopting the Commission's default pricing policy, including the "but for" standard for the purpose of the definition of network upgrades.[28] Further, we note the similarity between section 8.4 of Midwest ISO's Generator Interconnection Procedures and section 8.2 of the *pro forma* Generator Interconnection Procedures. Despite the presence of "Good Utility Practice" in section 8.2 of the *pro forma* Generator Interconnection Procedures, the Commission never suggested that section 8.2's reference to "Good Utility Practice" should be interpreted as expanding the meaning of "required"

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an individual project may be less than it would have been had the project been studied individually.

[27] Initial Order, 129 FERC ¶ 61,019 at P 29 (emphasis added).

[28] *See* Midwest Indep. Transmission Sys. Operator, Inc., Docket No. ER04-458-000, Transmittal Letter at 28-29, 32-33 (filed Jan. 20, 2004) (January 20, 2004 Filing); Midwest Indep. Transmission Sys. Operator, Inc., Docket No. ER04-458-001 (filed April 26, 2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,027, at P 136 (2004).

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for the purpose of the definition of network upgrades.[29] In other words, interconnection customers in Midwest ISO are required to fund the cost of network upgrades that would not have been needed but for their interconnection.

21. We clarify that this language does not limit Midwest ISO or its transmission owners to the least-cost option available to interconnect a generator or group of generators. The Tariff affords Midwest ISO some discretion when determining what facilities should be built in order to accommodate the interconnection of a project or group of projects. In particular, sections 7.1 and 8.1 of the Generator Interconnection Procedures recognize that Midwest ISO should use its study process to identify network upgrades that: (1) ensure that an interconnection customer or group of interconnection customers can reliably connect to the transmission system; and (2) ensure that the network upgrades chosen promote efficiency.[30] We do not doubt that a range of improvements could achieve these results. In addition, we have previously recognized that Midwest ISO's use of group studies allows it to focus on the needs of both the relevant interconnection customers and the overall system.[31]

22. Thus, Midwest ISO may determine through its study process that a large upgrade, such as the Brookings Line, should be built because it will both accommodate the interconnection of a group of projects and address other system-wide needs. However, the cost responsibility of a group of interconnection customers remains limited to the cost of the facilities that would not be needed but for the interconnection of the group. In this case, the evidence submitted indicated that the Brookings Line was needed for more than interconnection, but the cost allocation language in the Amended GIA was not sufficient to limit Community Wind's (or Group 5's) cost responsibility for the Brookings Line such that they were funding only the cost of upgrades that would not have been necessary but for their interconnection.[32] In other words, the evidence submitted does not support

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[29] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 221.

[30] *See* Tariff, Attachment X, First Revised Sheet No. 3082 (providing that the System Planning and Analysis Phase of the Midwest ISO study process, including an Interconnection System Impact Study, is designed to determine "Network Upgrades that will *reliably* and *efficiently* integrate the proposed Generating Facility" (emphasis added)), Second Revised Sheet No. 3085 (providing that the Definitive Planning Phase is designed to identify Network Upgrades that will *reliably* and *efficiently* integrate proposed generation into the Transmission Provider's Transmission Provider's Transmission System" (emphasis added)).

[31] Queue Reform Order, 124 FERC ¶ 61,183 at P 114.

[32] Initial Order, 129 FERC ¶ 61,019 at P 24.

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allocation of 100 percent of the costs of the Brookings Line to the Group 5 projects. Because the Initial Order's direction to remove the unsupported language relating to any cost responsibility for the Brookings Line could have been read to imply that the "but for" standard determines the network upgrades that can be built to accommodate an interconnection customer or group of interconnection customers, rather than is solely related to cost allocation, we will clarify the Initial Order and require a further compliance filing, as discussed below.

23. As to the suggestion that the Initial Order contravened Order No. 2003, we disagree. Midwest ISO correctly states that Order Nos. 2003 and 2003-A indicated that contingencies that may affect the cost responsibility of an interconnection customer and estimates of an interconnection customer's possible cost responsibility should be identified in an interconnection agreement.[33] However, in this case, Midwest ISO did not justify assigning responsibility for 100 percent of the costs of the Brookings Line to the Group 5 projects. The Transmittal Letter and Amended GIA properly characterized Community Wind's potential cost responsibility for the Brookings Line as a contingency risk,[34] but they do not make clear that Community Wind (or Group 5 as a whole) cannot be assessed the portions of the costs of the Brookings Line not attributable to interconnection. As discussed below, we will order Midwest ISO to revise the Amended GIA to properly describe the risk faced by Community Wind and the other Group 5 projects.

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[33] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 409. When discussing the possibility that a lower queued interconnection customer may be responsible for funding the costs of completing the network upgrades for a higher-queued Interconnection customer we stated that "[i]f it is apparent to the Parties at the time they executed the LGIA that contingencies (such as other interconnection customers terminating their LGIAs) might affect the financial arrangements, the Parties should include such contingencies in their LGIA and address the effect of such contingencies on their financial obligations." *Id. also see* Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 320 (directing the Transmission Provider to provide an estimate of the interconnection customer's maximum possible funding exposure, if higher queued generating facilities drop out when the Transmission Provider tenders the draft LGIA).

[34] *See* Filing, Transmittal Letter at 5-9.

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b. Timing and Cost Responsibility for Restudy

i. Rehearing Requests

24. Edison argues that the Commission erred by failing to specify that if Midwest ISO restudies the network upgrades for Community Wind and the other Group 5 projects, and re-files a proposal to allocate the costs of additional upgrades to Community Wind, it must do so within 60 days.[35] Edison argues that the Commission should order restudy within 60 days because time is of the essence for Community Wind and the interconnection of the project should not be further delayed by Midwest ISO's failure to identify the network upgrades required "but for" the interconnection of the Group 5 projects. Edison argues that 60 days is enough time for Midwest ISO to conduct a restudy, as section 8.7 of the Generator Interconnection Procedures states that Midwest ISO must use reasonable efforts to complete an Interconnection Facilities Restudy within 60 days if a higher-queued interconnection request is withdrawn or terminated.[36]

25. Edison also argues that the Commission erred by failing to specify that the costs of any restudy should not be imposed on Community Wind.[37] It asks the Commission to waive section 8.7 of the Generator Interconnection Procedures, which specifies that the cost of any Interconnection Facilities Restudy shall be borne by the interconnection customer, on the ground that the restudy will be the result of Midwest ISO's failure to comply with its Tariff.[38]

26. Midwest ISO states that restudy is necessary due to both the withdrawal of a number of projects, including a number of Group 5 projects, and the Initial Order's directive to remove the Brookings Line. If the Commission does not reverse the Initial Order and accept the results presented in the Amended GIA, Midwest ISO says that it will be required to perform a restudy to produce another alternative.[39] It adds that, since additional restudy is required, there will be further delay in achieving unfettered

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[35] Edison Request for Rehearing at 4 (citing Generator Interconnection Procedures, sections 1, 8.4, and 8.7).

[36] Edison Request for Rehearing at 7-8.

[37] *Id.* at 4.

[38] *Id.* at 8.

[39] Midwest ISO Request for Rehearing at 50.

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interconnection service, and it notes that Community Wind has failed to meet certain milestones in its Amended GIA and is subject to a declaration of default.[40]

27. Midwest ISO states that removing the Brookings Line from the GIA of Community Wind and other Group 5 projects will require extensive restudy and provides estimates of the time that it will take to restudy the Group 5 projects.[41] Finally, Midwest ISO commits to continuing to work towards resolving the Brookings Line issue and still believes that it is possible to make further progress through negotiation. Accordingly, Midwest ISO plans on providing restudy agreements to the Group 5 projects and other effected parties in order to move forward to the extent possible.[42]

ii. Commission Determination

28. We deny Edison's request that we order Midwest ISO to restudy and file a revised Amended GIA within 60 days. Midwest ISO has indicated that restudy is required in any event under the Tariff, due to the withdrawal of several projects. Section 8.7 requires Midwest ISO to use reasonable efforts to complete restudy within 60 days, and so we find it unnecessary to impose this deadline by order. We also deny Edison's request for waiver of section 8.7 of the Generator Interconnection Procedures, to prohibit Midwest ISO from charging Community Wind and the other Group 5 projects for any restudy. As Midwest ISO indicates, restudy is required because of the withdrawal of higher-queued generators.

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[40] *Id.* at 51.

[41] *Id.* at 52-53. Midwest ISO states that restudy will take approximately 128 days if it is required to demonstrate not only that the Brookings Line is a solution to the stability problems arising from the interconnection of the Group 5 projects but the prudence of alternative solutions as well. Midwest ISO states that Community Wind and other interveners have acknowledged that a stability problem arises from the interconnection of the Group 5 projects, but that they have not stipulated that the correct problem has been identified and quantified to the point that a restudy can start. Midwest ISO states that if the Group 5 projects contest that the problem exists, restudy will take an additional 108 days.

[42] *Id.*

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c. Applicable Cost Allocation Methodology

i. Rehearing Requests

29. Midwest ISO argues that the Initial Order's application of Attachment FF is arbitrary and inconsistent with the "but for" standard. It states that the Commission acted inconsistently by relying on Attachment FF of the Tariff to conclude that the "but for" standard limits the cost responsibility of an interconnection customer, while later stating that ongoing revisions to the cost allocation procedures under Attachment FF pending before the Commission in Docket No. ER09-1431 (RECB III proceedings)[43] "may impact Community Wind's eligibility for reimbursement for the costs of network upgrades, [but] do not address whether Community Wind can be required to fund the costs of the Brookings Line in the first place."[44]

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[43] In Order No. 2003, the Commission recognized that independent transmission providers could propose alternative allocation methodologies for the costs of network upgrades associated with generator interconnection. When acting on Midwest ISO's Order No. 2003 compliance filing, the Commission encouraged Midwest ISO to work with stakeholders to develop a network upgrade pricing policy. Midwest ISO then proposed, and the Commission accepted, tariff language providing that if, at the time the interconnection customer achieved commercial operation, the interconnection customer demonstrated that its generator had been 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 percent of the costs of the network upgrades for the Generation Interconnection Project would be repaid to the interconnection customer (50-50 cost sharing methodology). *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,106 (RECB I), *order on reh'g*, 117 FERC ¶ 61,241 (2006), *aff'd sub nom. Pub. Serv. Comm'n of Wis. v. FERC*, 543 F.3d 1058 (D.C. Cir. 2008). On October 23, 2009, in Docket No. ER09-1431, the Commission conditionally accepted Midwest ISO's proposal to replace the 50-50 cost sharing methodology with an interim methodology providing that an interconnection customer would bear 100 percent of the costs of network upgrades rated below 345 kV, and 90 percent of the costs of network upgrades rated at 345 kV and above (with the remaining 10 percent recovered on a system-wide basis). *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 (2009) (RECB III Order). Midwest ISO is expected to file a further revised cost allocation methodology by July 2010.

[44] Midwest ISO Request for Rehearing at 48-49 (quoting Initial Order, 129 FERC ¶ 61,019 at P 26).

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30. Xcel requests clarification of an issue arising from the RECB III Order. Xcel states that, since the parties had an executed Temporary GIA dated December 9, 2008, but the Initial Order accepts the unexecuted Amended GIA for filing effective August 14, 2009, it appears the Amended GIA is the legally binding GIA. Xcel notes that the RECB III Order applies the RECB III allocation methodology, which requires the interconnection customer to fund either 100 percent or 90 percent of all network upgrades, to all GIAs executed or filed unexecuted after July 9, 2009. Xcel contends that there is uncertainty about whether Community Wind would have a RECB cost allocation grandfathered by virtue of its Temporary GIA or if Community Wind would be subject to the RECB III allocation made effective July 10, 2009.[45] Xcel states that it interprets the Initial Order as requiring Community Wind to provide funding under the RECB III methodology but argues that the Commission should clarify this point to avoid any future misunderstandings between the Parties.

ii. Commission Determination

31. We will deny Midwest ISO's request for rehearing to the extent that it argues that the Initial Order's application of Attachment FF is arbitrary and inconsistent with the "but for" standard. Attachment FF provides that all costs of Generator Interconnection Projects will be funded initially by the relevant interconnection customer in accordance with the Generator Interconnection Procedures which, as discussed above, use the "but for" standard. While the "but for" standard limits the costs that an interconnection customer can be required to fund initially, the revisions accepted in the RECB III Order affect only the extent to which an interconnection customer can be reimbursed after funding the costs of a Generator Interconnection Project.

32. We clarify that the mere fact that Community Wind had a Temporary GIA does not grandfather any particular cost allocation methodology. As we stated in the RECB III Order, the "[t]ariff that should apply is the one that is effective and on file on the date that the interconnection agreement is executed or filed unexecuted."[46] Here, the Amended GIA was filed unexecuted on August 13, 2009. Accordingly, the cost allocation methodology that was effective and on file on that date—the RECB III cost allocation methodology—would apply to any network upgrades that Community Wind is obligated to fund under the Amended GIA. The Amended GIA currently provides that there are no network upgrades under the Amended GIA that Community Wind is required to fund,

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[45] Xcel Request for Rehearing at 12.

[46] RECB III Order, 129 FERC ¶ 61,060 at 62 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,277, at P 10 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,106, at P 70 (2006)).

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and that a subsequent multi-party facilities construction agreement will govern the obligation of Community Wind and the Group 5 projects to secure and fund the Shared Ownership Common Use Upgrades,[47] including the Brookings Line. Therefore, the Group 5 projects' obligations to secure and fund the Brookings Line will be governed under a future multi-party facility construction agreement and such responsibility will depend on the Tariff allocation methodology that applies to that agreement.

d. Transmission Planning

i. Rehearing Requests

33. Xcel asks how the "but for" standard should be applied in circumstances where a regional planning process under Order No. 890 develops plans for comprehensive regional transmission upgrades that are different than those that an incremental "but for" analysis, including a group study, might conclude are necessary. Xcel states that the initial Group 5 studies indicated that the interconnection of the Group 5 projects would require the construction of more than $500 million in new transmission facilities.[48] Xcel states that the Brookings Line was subsequently added in order to solve the model and to provide adequate transmission for the Group 5 projects, and, thereby, make the various facilities identified by the initial Group 5 study facilities unnecessary.

34. Xcel states that if this docket is not the appropriate forum in which to address this policy issue, the Commission should clarify that Midwest ISO and its stakeholders must address this issue in the compliance filing required by the RECB III Order and that the permanent cost methodology to be filed in July 2010 may be applied to the Brookings Line. In the alternative, Xcel states that the Commission should set these issues for a technical conference because of the complex technical issues relevant to a determination in this matter.[49]

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[47] The Amended GIA distinguishes among several types of network upgrades: Common Use Upgrades, Shared Ownership Common Use Upgrades, and network upgrades. The Amended GIA refers to the Brookings Line as a Shared Ownership Common Use Upgrade. *See* Filing at Original Sheets 99-105.

[48] Xcel Request for Rehearing at 14-15.

[49] *Id.* at 18.

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ii. Commission Determination

35. We reject Xcel's request for clarification. This is not an appropriate forum in which to generically address the policy issue concerning the relationship between the cost allocation principles articulated in Order No. 2003 and the planning process embraced in Order No. 890. The issues in this proceeding are limited to the responsibility of the Group 5 projects for the costs of the Brookings Line. Further, because Xcel is asking for clarification of a broad policy issue through its request for rehearing, we do not have the range of input that would be necessary to make such a decision. Xcel has failed to persuade us that we should "clarify" that Midwest ISO and its stakeholders must address this policy issue in the compliance filing required by the RECB III Order or that we should set these issues for technical conference in this proceeding.

e. The Need to Restudy, Status of the Amended GIA, and Status of Community Wind

i. Rehearing Requests

36. Midwest ISO argues that the Initial Order violates the FPA to the extent that it invites Midwest ISO to re-file the Amended GIA without prejudice, but does not address the need for a restudy.[50] Midwest ISO argues that the effect of the Initial Order on other Group 5 projects is unclear. Midwest ISO claims that one implication of the Initial Order may be that the Brookings Line should not be listed as a contingency for any Group 5 project until additional justification is provided.[51]

37. Midwest ISO argues that the Initial Order should be reversed or clarified to require Midwest ISO to refile the Amended GIA as a provisional GIA under section 11.5 of the Generator Interconnection Procedures. Midwest ISO contends that complying with the Initial Order would require it to violate North American Electric Reliability Corporation (NERC) reliability standards, Commission precedent, and the Tariff. At the very least, Midwest ISO asks the Commission to clarify that removal of the Brookings Line as a contingency listed in the appendices of the Amended GIA returns the Amended GIA to the status of a provisional GIA, subject to the outcome of restudy to determine the appropriate network upgrades.

38. Xcel requests clarification that Community Wind is only eligible for the limited interconnection capabilities and operations made possible by the specific interconnection

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[50] Midwest ISO Request for Rehearing at 7.

[51] *Id.* at 50.

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facilities and network upgrades remaining in the Amended GIA until the Group 5 common use network upgrades are identified in a restudy and allocated to Community Wind in a further Amended GIA or multi-party facilities construction agreement. Xcel asks the Commission to clarify that if the Brookings Line is omitted from Appendix A, Northern States is only obligated to install the network upgrades and interconnection facilities that remain in Appendix A, as amended. Xcel notes that the Amended GIA currently obligates the Transmission Owner to construct and design the network upgrades in Appendix A and then indicates that there are currently no network upgrades that the Transmission Owner is obligated to build under the Amended GIA.[52]

39. Great River asks the Commission to clarify that the Initial Order does not preclude Midwest ISO from allocating the costs of the Brookings Line to Community Wind and other Group 5 projects if Midwest ISO demonstrates that the Brookings Line is required to interconnect the projects to the transmission system.[53] Great River expresses concern that the Initial Order will be erroneously interpreted as stating that Midwest ISO can subsequently provide evidence that the Brookings Line is required for the interconnection of the Group 5 projects, but not for Community Wind.[54] Great River argues that such a result could jeopardize system reliability and run afoul of the Midwest ISO group study process, and, thereby, undermine regional efforts to plan for the types of network upgrades that would allow large additions of wind generation to the system.[55] Great River states that, to the extent that the Commission does not grant the requested clarification, the Commission should grant rehearing of the Initial Order because it accepted the Amended GIA without an evidentiary or paper hearing.[56]

40. Similarly, Xcel seeks rehearing or clarification that Community Wind was appropriately studied as part of Group 5, and that the results of any restudies of Group 5 must be comparably applied to Community Wind in a future multi-party facilities construction agreement and/or amendment to Appendix A of the Amended GIA.[57] Xcel states that the Commission strongly encouraged the use of clustering in Order No. 2003-A and acknowledged that a Transmission Provider may allocate the cost of common use

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[52] Xcel Request for Rehearing at 18 (citing Amended GIA, Original Sheet Nos. 57, 99).

[53] Great River Request for Rehearing at 2.

[54] *Id.* at 4.

[55] *Id.* at 6.

[56] *Id.* at 6-8.

[57] Xcel Request for Rehearing at 8, 11-12.

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upgrades for clustered interconnection requests without regard to queue position.[58] Xcel contends that it is unclear how to marry the guidance and directives provided by the Commission in Order No. 2003-A and the Initial Order. Xcel states that it interprets the Initial Order and Commissioner Kelly's partial dissent to allow a future amendment to the Amended GIA to include such common use upgrade costs identified by Midwest ISO with additional supporting evidence. Xcel asks the Commission to clarify that the Initial Order does not preclude Midwest ISO's continued use of the group study process for the Group 5 projects.[59]

ii. Commission Determination

41. As discussed above, we clarify that, under the Tariff, the "but for" standard is merely a cost allocation principle and does not determine the network upgrades that can be built to accommodate an interconnection request or group of interconnection requests. The Commission's concern with the cost allocation language in the Amended GIA was that it was not sufficient to limit Community Wind's (or Group 5's) cost responsibility for the Brookings Line such that they were funding only the cost of upgrades that would not have been necessary but for their interconnection. However, in ordering Midwest ISO to delete unsupported language relating to any cost responsibility of Community Wind or other Group 5 projects for the costs of the Brookings Line, the Commission did not intend that Midwest ISO revert the Amended GIA to a temporary or provisional GIA or to prejudice the outcome of any future proceeding concerning allocation of the costs of the Brookings Line to Community Wind or other Group 5 projects following restudy. Nor did the Commission intend to suggest that Midwest ISO was required to delete *all* references to the Brookings Line in the Amended GIA.

42. We will direct Midwest ISO to revise the language of Appendix A of its Amended GIA[60] so that it more correctly describes the limits of the risk that Community Wind and other Group 5 projects face regarding construction of the Brookings Line.[61] We note that

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[58] *Id.* at 10.

[59] *Id.* at 11.

[60] We note that we are dismissing Midwest ISO's Compliance Filing which reverted the Amended GIA to a provisional GIA and that we expect that the compliance filing ordered below will retain the permanent character of the Amended GIA.

[61] We do not expect that Midwest ISO will submit information specifically delineating what portion of the Brookings Line is attributable to the Group 5 projects in the compliance filing ordered below. We expect that such information would be

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section 2(i) of Appendix A provides that the "Group 5 Generators' obligations to simultaneously secure and fund [the] Common Use Upgrades and Shared Ownership Common Use Upgrades will . . . be the subject matter governed by [the multi-party facilities construction agreements] to be developed by [the] Transmission Provider . . . ."[62] Sections 2(ii) and 2(iii) also refer to future agreements, but the language of those provisions is not as clear as the language of section 2(i). We therefore direct Midwest ISO to revise the language of sections 2(ii) and 2(iii) of Appendix A so that they are consistent with the language of section 2(i). All three subsections should state that Community Wind shares cost responsibility for the Brookings Line only to the extent that the Brookings Line would not have been necessary but for the interconnection of the group.

43. Further, we will direct Midwest ISO to remove Table 5 from the Amended GIA. The cost estimates provided therein have little value in light of the parties' acknowledgement that restudy of the Group 5 projects is required and Midwest ISO's failure to demonstrate that 100 percent of the costs of the Brookings Line should be allocated to the Group 5 projects.

44. Our decision to grant clarification of the Initial Order and to allow Midwest ISO to retain references to the Brookings Line in the Amended GIA makes it unnecessary to address the arguments that the Initial Order erred by failing to address the need for restudy and that compliance with the Initial Order would require Midwest ISO to violate reliability standards. Likewise, we find that it is unnecessary to address requests for clarification regarding the status of the Amended GIA and multi-party facilities construction agreement because of our decision to allow Midwest ISO to retain references to the Brookings Line.

45. Finally, we reiterate that Midwest ISO has indicated that the conditions for restudy listed in section 8.7 have been met and emphasize that section 8.7 directs Midwest ISO to use reasonable efforts to complete any such restudy within 60 days.

2. Compliance Filing

46. In the Compliance Filing, Midwest ISO proposes to omit any reference to the Brookings Line. However, as explained above, the Commission merely meant that Midwest ISO should remove unsupported language relating to cost allocation. In light of

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submitted when Midwest ISO files the multi-party facilities construction agreement governing the Brookings Line.

[62] Filing at Original Sheet No. 90.

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EXHIBIT B

our clarifications above, and given our decision to require Midwest ISO to further revise the language of the Amended GIA as discussed above, we will dismiss the Compliance Filing submitted in Docket No. ER09-1581-003. We therefore need not address the protests to that filing.

The Commission orders:

(A) The requests for rehearing of the Initial Order are hereby denied and the requests for clarification of the Initial Order are hereby granted in part and denied in part, as discussed in the body of this order.

(B) Midwest ISO's Compliance Filing is hereby dismissed, as discussed in the body of this order.

(C) Midwest ISO is hereby directed to make a further compliance filing, within 30 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Exhibit C

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EXHIBIT C

133 FERC ¶ 61,221
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER10-1791-000

ORDER CONDITIONALLY ACCEPTING TARIFF REVISIONS

(Issued December 16, 2010)

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1. On July 15, 2010, pursuant to section 205 of the Federal Power Act (FPA),[1] and in accordance with the Commission's October 23, 2009 order,[2] Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and Midwest ISO Transmission Owners[3] (collectively, Filing Parties) filed proposed revisions to the Midwest ISO Open

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[1] 16 U.S.C. § 824d (2006).

[2] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060, at P 68-70 (2009) (October 23, 2009 Order) ("We deny the requests to establish a sunset date for Filing Parties' section 205 Phase I cost allocation methodology because Filing Parties have already committed 'to file the long-term Phase II cost allocation methodology by July 15, 2010. We will, however, condition the acceptance of the instant proposal on Filing Parties fulfilling their commitment to file tariff sheets reflecting the Phase II solution on or before July 15, 2010.'" (footnote omitted)), *reh'g pending*.

[3] For purposes of this filing, Midwest ISO Transmission Owners include Ameren Services Company, as agent for Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Co., and Illinois Power Company; American Transmission Company LLC (ATC); 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 (Minnesota); Northern States Power Company (Wisconsin); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company; and Southern Minnesota Municipal Power Agency.

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Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff)[4] (July 15 Filing). Filing Parties propose to establish a new category of transmission projects designated as Multi Value Projects (MVP) for projects that are determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones.[5] In recognizing the regional orientation of such projects, Filing Parties propose that the costs of the MVPs be allocated to all load in, and exports from, Midwest ISO on a postage-stamp basis. Filing Parties also propose to make permanent the interim cost allocation methodology for generator interconnection upgrades[6] conditionally approved in the Commission's October 23, 2009 Order but propose revisions to narrow the cost burden faced by an initial generator interconnection customer that funds a network upgrade by requiring subsequent interconnection customers that benefit from the same upgrade to contribute to the costs of such upgrade through the creation of a new class of interconnection projects call Shared Network Upgrades (SNU).

2. As the Commission has noted before, cost allocation reform is one of the most difficult issues facing transmission service providers and regional transmission organizations (RTO) and independent system operators (ISO), including Midwest ISO. This is especially true given the changing circumstances affecting the transmission grid, including particularly, the need to upgrade existing transmission infrastructure and build new transmission facilities to satisfy the expanding demands on the transmission system.

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[4] Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No.1. When referring to the applicants, this order uses "Filing Parties" and "Midwest ISO" interchangeably unless otherwise noted.

[5] The Commission has shown interest in expanding transmission planning processes and exploring cost allocation issues in its currently pending Notice of Proposed Rulemaking in Docket No. RM10-23-000. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, 75 Fed. Reg. 37884 (June 30, 2010), FERC Stats. & Regs. ¶ 32,660 (2010) (Transmission NOPR). Because the Commission's action today on Filing Parties' MVP proposal precedes any final rule on the Transmission NOPR, we have reviewed the MVP proposal to ensure consistency with existing Commission policies. Midwest ISO, like all jurisdictional entities, will be subject to any future rulemakings.

[6] This methodology assigns to interconnection customers 100 percent of the costs of network upgrades rated below 345 kilovolts (kV) and 90 percent of the network upgrades rated at 345 kV and above, with the remaining 10 percent of the costs being recovered on a system-wide basis.

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Efforts to integrate new resources, including significant amounts of location-constrained generation, into existing transmission systems and to address renewable portfolio standards and other regulatory policies challenge existing transmission planning and cost allocation protocols.[7] The expansion of energy markets across the Midwest ISO region, the need to modernize aging infrastructure, and the necessity of maintaining reliable service are also testing existing transmission planning and cost allocation mechanisms.

3. Here, we conditionally accept Filing Parties' proposed Tariff revisions for filing effective July 16, 2010, as further discussed herein. We find that the MVP methodology will identify projects that provide regional benefits and allocate the costs of those projects accordingly. The proposed MVP methodology is an important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or growing loads. We also find the proposal to maintain the existing cost reimbursement policy for network upgrades, along with the addition of the new classification of projects as SNUs, to be appropriate, as it provides a better balance for allocating cost responsibilities for large network upgrades associated with interconnecting with the electric transmission grid.

4. As explained below, our acceptance is conditioned on Filing Parties submitting a compliance filing that: 1) states in the Tariff that they will review MVPs on a portfolio basis; 2) revises the Tariff to ensure that the MVP usage rate is not applied to export or wheel-through transactions that sink in the PJM region; 3) provides an explanation as to how the proposed Tariff language relating to Monthly Net Actual Energy Withdrawal and Demand Response Resources and Emergency Demand Response resources is consistent with the rate design objectives stated by Filing Parties, and why it does not result in double netting; and 4) revises the Tariff to clarify that the divisor of the MVP usage charge in Attachment MM reflects the MWhs of grandfathered service provided by each

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[7] *See, e.g.*, October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58 ("The Commission has previously recognized that location-constrained resources present unique challenges that other resources do not present. For example, in *CAISO*, the Commission concluded that the barriers to the development of interconnection infrastructure to location-constrained resources highlight the need for flexibility in applying the Commission's interconnection policy to accommodate these resources. The Commission also has acknowledged 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" (footnotes omitted)). *See also Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 2 (2010) (SPP June 17, 2010 Order).

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transmission owner to reflect an allocation of the costs of MVPs recovered under grandfathered agreements. We also require Filing Parties to submit a compliance filing no later than June 1, 2011 to describe what changes are required to its allocation of Financial Transmission Rights and Auction Revenue Rights in order to reflect the usage-based allocation of MVP costs being accepted here. We further require Midwest ISO to file ongoing annual informational reports[8] with the Commission describing the selection of MVPs, including the achievements and shortcomings of the MVP selection process, after each full planning cycle has been completed.

I. Background

A. Commission-Directed Reform of Transmission Planning Process

5. In Order No. 890,[9] the Commission reformed the *pro forma* open access transmission tariff (OATT) to clarify and expand the obligations of transmission providers to ensure that transmission service is provided on a non-discriminatory basis. One of the Commission's primary reforms was designed to address the lack of specificity regarding how customers and other stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in planning activities, the Commission directed all transmission providers to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to their OATT (Attachment K).

6. The nine planning principles each transmission provider was directed by Order No. 890 to address in its Attachment K planning process are: 1) coordination; 2) openness; 3) transparency; 4) information exchange; 5) comparability;[10] 6) dispute

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[8] The Commission does not intend to issue public notices, accept comments, or issue orders on such informational filings.

[9] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, 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).

[10] In Order No. 890-A, the Commission clarified that the comparability principle requires each transmission provider to identify, as part of its Attachment K planning process, how it will treat resources on a comparable basis and, therefore, how it will determine comparability for purposes of transmission planning. *See* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216.

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resolution; 7) regional participation; 8) economic planning studies; and 9) cost allocation for new projects. The Commission explained that it adopted a principles-based reform to allow for flexibility in implementation of and to build on transmission planning efforts and processes already underway in many regions of the country. The Commission also explained, however, that although Order No. 890 allows for flexibility, each transmission provider has a clear obligation to address each of the nine principles in its transmission planning process, and all of these principles must be fully addressed in the tariff language filed with the Commission. The Commission emphasized that tariff rules, as supplemented with web-posted business practices when appropriate,[11] must be specific and clear in order to facilitate compliance by transmission providers and place customers on notice of their rights and obligations.

7. As for RTOs and ISOs with Commission-approved transmission planning processes already on file, such as Midwest ISO, the Commission explained that, when it initially approved these processes, they were found to be consistent with or superior to the existing *pro forma* OATT. However, because the *pro forma* OATT was being reformed by Order No. 890, the Commission found that it was necessary for each RTO and ISO either to reform its planning process or show that its planning process is consistent with or superior to the *pro forma* OATT, as modified by Order Nos. 890 and 890-A.[12]

8. On December 7, 2007, Midwest ISO made its filing in Docket No. OA08-53-000 in compliance with Order No. 890's planning requirements. In the May 2008 Planning Order,[13] the Commission accepted that compliance filing, as modified, to be effective December 7, 2007, subject to a further compliance filing. On August 13, 2008, Midwest ISO made its filing in Docket No. OA08-53-001 in compliance with the May 2008

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[11] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1649-55.

[12] *See id.* at P 439; Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 174-75. The Commission also reviewed stakeholder processes as part of Order No. 719. *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719 or Final Rule), *order on reh'g*, Order No. 719-A, 74 Fed. Reg. 37776 (Jul. 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[13] *Midwest Indep. Transmission Sys. Operator, Inc.*, 123 FERC ¶ 61,164 (2008) (May 2008 Planning Order).

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Planning Order. In the May 2009 Planning Order,[14] the Commission accepted that compliance filing, as modified, subject to a further compliance filing. On July 20, 2009, Midwest ISO submitted its filing in Docket No. OA08-53-002 in compliance with the May 2009 Planning Order. In the March 2010 Planning Order, the Commission accepted that compliance filing, as modified.[15] On April 23, 2010, in Docket No. OA08-53-003, Midwest ISO filed proposed revisions to Attachment FF of the Midwest ISO Tariff to comply with the Commission's directives in the March 2010 Planning Order.[16]

B. Existing Midwest ISO Cost Allocation Methodologies

9. Filing Parties state that the proposed Tariff changes are part of an ongoing, comprehensive review of all of Midwest ISO's Regional Expansion Criteria and Benefits (RECB) transmission cost allocation methodologies that are currently in effect in its Tariff. In the instant filing, Filing Parties propose to establish a new category of projects designated as MVPs and to permanently maintain the interim generator interconnection policy whereby generator interconnection customers throughout most of Midwest ISO will be responsible for 90 or 100 percent of the costs to interconnect to the transmission system, depending on the voltage classification of the interconnection network upgrades. They propose to retain the existing cost allocation methodologies for Baseline Reliability Projects (as approved in the RECB I proceeding[17]) and Regionally Beneficial Projects (renamed Market Efficiency Projects in the instant filing) (as approved in the RECB II proceeding[18]) until such time as their comprehensive review is completed.

10. Under Midwest ISO's currently-effective Tariff, Baseline Reliability Projects are included in the Midwest ISO Transmission Expansion Plan and are needed to maintain reliability, while accommodating the ongoing needs of existing transmission customers.

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[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,169 (2009) (May 2009 Planning Order).

[15] *Midwest Indep. Transmission Sys. Operator, Inc.*, 130 FERC ¶ 61,232 (2010) (March 2010 Planning Order).

[16] Midwest ISO's April 23, 2010 compliance filing is currently pending before the Commission.

[17] *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,106, *order on reh'g*, 117 FERC ¶ 61,241 (2006) (RECB I Order).

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

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To qualify for cost sharing, such projects must meet a materiality test (i.e., cost at least $5 million or 5 percent of the net plant of the transmission owner). For projects rated at or above 345 kV, 20 percent of the cost of the projects is allocated on a load-ratio share (i.e., postage-stamp) basis throughout Midwest ISO. The remaining project cost is allocated sub-regionally (potentially across several affected pricing zones) based on Line Outage Distribution Factor analyses.[19] For projects rated between 100kV and 344kV, all of the project cost is allocated sub-regionally based on Line Outage Distribution Factor analyses. The Commission approved this method in Midwest ISO's RECB I proceeding.

11. The RECB I proceeding also established cost allocation rules for generator interconnection projects (GIP), which are network upgrades that would not be required "but for" the interconnection of new or increased generating capacity. As accepted by the Commission in 2006, the RECB I proposal required the interconnection customer to pay the entire cost of network upgrades in advance. 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 a contract of at least one year to supply capacity or energy to a network customer, then 50 percent of the costs of the network upgrades is repaid to the interconnection customer and recovered from transmission customers through the same cost allocation rule that applies to Baseline Reliability Projects. Otherwise, the interconnection customer is directly assigned 100 percent of the costs. Exceptions to this policy have been granted to International Transmission Company and Michigan Electric Transmission Company LLC and ATC.[20]

12. Under Midwest ISO's currently-effective Tariff, Regionally Beneficial Projects are economic upgrades that meet specific standards. To qualify for cost sharing, the project must first satisfy two benefits tests as well as a materiality test. The benefits tests are: 1) the present value of the sum of the production cost benefit and the Locational Marginal Pricing (LMP)-based energy cost benefit must be greater than zero; and 2) the proposed project must satisfy a variable project Benefit/Costs Ratio threshold (where Benefit = 0.7*production cost benefit + 0.3*LMP benefit). This threshold varies linearly from 1.2 (for projects with an in-service date within 1 year) to 3.0 (for projects with an in-service date 10 or more years out). The materiality test requires that the project: 1)

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[19] The Line Outage Distribution Factor method considers the flow effects of a given facility's outage on transmission facilities in each pricing zone, also taking into account the length of each affected transmission facility.

[20] *International Transmission Company, et al.*, 120 FERC ¶ 61,220 (2007), *reh'g denied*, 123 FERC ¶ 61,065 (2008); *American Transmission Company, LLC, et al.*, 120 FERC ¶ 61,221 (2007), *reh'g denied*, 123 FERC ¶ 61,065 (2008); *ITC Midwest LLC*, 124 FERC ¶ 61,150 (2008) (August 7, 2008 Order).

cost more than $5 million; 2) involve facilities with voltages of 345 kV or more (high-voltage); and 3) not be designated as either a Baseline Reliability Project or a Transmission Access Project.

13. If the project meets the benefits and materiality tests, then 20 percent of the project cost is allocated on a load share basis throughout Midwest ISO. The remaining 80 percent of the cost is allocated to three sub-regions based on a Weighted Gain-No Loss beneficiary analysis where the Weighted Gain-No Loss metric for each planning sub-region is the weighted sum of 70 percent of the production cost benefit and 30 percent of the LMP energy cost benefit metric over the entire modeling period. However, if a sub-region does not benefit from the project (i.e., the weighted sum of the production cost benefit and the LMP energy cost benefit is negative), such sub-region will not see a share of the 80 percent of project cost.

14. On March 15, 2007, the Commission conditionally accepted the RECB II proposal.[21] On rehearing, the Commission further directed Midwest ISO to make informational reports in August 2008 and August 2009 that analyze the effectiveness of all of the transmission expansion cost allocation methodologies.[22]

15. In its August 2008 report, 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 possible solutions, through the RECB Task Force. Midwest 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.

16. On July 9, 2009, in Docket No. ER09-1431-000, Midwest ISO and certain Midwest ISO transmission owners (July 9 Applicants) filed an interim cost allocation proposal (Interim Cost Allocation Proposal) to address certain unanticipated consequences experienced under the then-effective RECB cost allocation rules for GIPs. As described by July 9 Applicants, zones with high wind-power development potential and low native load were burdened with a disproportionate share of the costs of GIPs. July 9 Applicants proposed to: 1) eliminate the Line Outage Distribution Factor analysis-based allocation of GIPs to load in pricing zones; 2) assign, to interconnection customers, the share of costs previously allocated to loads based on the Line Outage Distribution

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[21] RECB II Order, 118 FERC ¶ 61,209, RECB II Rehearing Order, 120 FERC ¶ 61,080.

[22] RECB II Rehearing Order, 120 FERC ¶ 61,080 at P 9.

Factor analysis; and 3) eliminate the requirement that an interconnection customer demonstrate that it has been designated as a Midwest ISO network resource or that it has executed a power purchase agreement for a period of at least one year with a network customer to be eligible for cost sharing. Under the Interim Cost Allocation Proposal, interconnection customers would be responsible for 100 percent of the costs of GIPs rated below 345 kV and 90 percent of the costs of GIPs rated at 345 kV and above (with the remaining 10 percent being recovered on a system-wide basis). Midwest ISO also offered to provide the Commission with quarterly reports on the status of its Phase II stakeholder discussions.

17. In the October 23, 2009 Order, the Commission accepted the Interim Cost Allocation Proposal conditioned upon the July 9 Applicants meeting their commitment to file superseding Tariff revisions on or before July 15, 2010, and required informational status reports to be submitted on November 20, 2009, February 26, 2010, and May 28, 2010. The Commission also recognized that Midwest ISO was engaged in a stakeholder process that was looking at a longer-term solution to the existing cost allocation issues. The Commission strongly encouraged Midwest ISO and its stakeholders to dedicate themselves to use the stakeholder process for the evaluation of Phase II reforms to transmission planning and cost allocation to more efficiently plan transmission expansions to interconnect and integrate new generation resources. The Commission suggested 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."[23]

C. Stakeholder Process

18. Filing Parties state that the instant filing is the result of months of Midwest ISO stakeholder and RECB Task Force discussions in close coordination with the Organization of MISO States (OMS) through its focused Cost Allocation and Regional Planning (CARP) working group for the purpose of addressing the Commission's directive in the October 23, 2009 Order. The work of these stakeholder groups and the involvement of the Midwest ISO transmission owners is detailed in the informational reports filed by Midwest ISO pursuant to the October 23, 2009 Order.

19. Formed in January 2009, CARP is comprised of one Commissioner (or their proxy) from each of the Midwest ISO member states. Each state gets one vote on each matter brought before the group. CARP requests that Midwest ISO staff perform analyses and run scenarios in order to provide useful information for CARP to then

[23] October 23, 2009 Order, 129 FERC ¶ 61,060 at P 60.

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evaluate and vote on. Commissioner Lauren Azar of Public Service Commission of Wisconsin is the Chair of CARP. The meetings are open to the public, but active participation is limited to the OMS representatives.

20. The RECB Task Force Phase II began on June 24, 2009. The purpose of the RECB Task Force Phase II was to develop Tariff language focused on a permanent cost allocation methodology to evaluate and/or amend the interim cost allocation methodology. Commissioner Lauren Azar also served as the Chair of this group. The primary difference between the RECB Task Force Phase II and CARP was the open involvement of interested stakeholders. Whereas CARP participation was limited to OMS representatives, the RECB Task Force Phase II was an open, Midwest ISO-wide stakeholder forum.

21. During the same period, Midwest ISO developed potential solutions using its analysis along with input from CARP and the RECB Task Force Phase II. Eventually, three solutions to the generator interconnection problem were proposed. Those proposed solutions were developed by: 1) Midwest ISO; 2) certain Midwest ISO transmission owners; and 3) CARP.

22. During the stakeholder process, Midwest ISO originally proposed a hybrid between injection-withdrawal and highway-byway methodologies.[24] The injection component would be used for local costs and be calculated based on existing pricing zones or a combination of pricing zones and on a 12-month coincident peak or nameplate capacity (demand-based) methodology. A transmission usage study within each zone would produce the actual percentages assigned to either injections or withdrawals. For example, in zones with significantly more generation than load, the generators would have a larger percentage of the "local" revenue requirement. Regional costs would be allocated 100-percent region-wide to load using a usage or megawatt-hour (MWh) charge. Midwest ISO stated that that proposal would address the issues raised by the

[24] Midwest ISO November 20, 2009 Informational Report, Docket No. ER09-1431-000.

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LECG Report[25] on the original pure injection/withdrawal methodology initially considered by CARP.[26]

23. Certain Midwest ISO transmission owners presented an alternative that included transmission system overlay projects called unique purpose projects. Unique purpose projects would be identified during Midwest ISO's MTEP Planning Process with stakeholder input to the combined top-down and bottom-up analysis and would be approved for construction by the Midwest ISO Board of Directors (Midwest ISO Board). Unique purpose projects would enable public policy goals, be indentified through the Midwest ISO planning process, and be vetted through the stakeholders. This proposal assigned 100 percent of the costs of unique purpose projects to load on a postage-stamp basis and 100 percent of the costs of generation interconnection upgrades to generators.[27]

24. An OMS CARP proposal was similar to the Midwest ISO transmission owner proposal described above. However, 20 percent of the costs were allocated to generators on a region-wide basis.[28]

25. After considering the different proposed solutions, Filing Parties developed their instant proposal. The instant proposal uses inputs from CARP, the RECB Task Force Phase III and Midwest ISO Transmission Owners. Midwest ISO further designed the

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[25] Scott Harvey and Susan Pope, LECG, LLC, *Evaluation of MVP Transmission Cost Allocation Design* (June 9, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7db40a48324a/Item%2003a%20-%20EvaIuation%20of%20MVP%20Transmission%20CA%20Design.pdf?action=download&_property=Attachment (LECG Report).

[26] The LECG Report on the effects of injection-withdrawal highlighted a few potential problems with the market. Mr. Scott Harvey stated that usage charges on energy storage resources (e.g., Ludington Pumped Storage) will tend to overcharge such a unit and could hamper further involvement in the market. This could be a barrier to future entries and could also have a negative effect on wind involvement. Mr. Harvey also claimed that usage charges (MWh charges instead of megawatt (MW) charges) that vary by sub-region should be avoided, as they could have a negative effect on competition. The LECG Report also found that the proposed methodology could produce some significant unpredictability regarding future grid upgrades.

[27] Midwest ISO May 28, 2010 Informational Report, Docket No. ER09-1431-000.

[28] *Id.*

unique purpose project definition to become the instant MVP proposal. Midwest ISO also determined not to assign the costs of MVPs to generators, while also making permanent the interim cost allocation methodology for GIPs.[29]

II. The Instant Filing

26. Filing Parties state that Midwest ISO and its stakeholders have fully considered the October 23, 2009 Order's directives in developing the MVP and generator interconnection network upgrade proposals. They state that the instant proposal recognizes evolving industry and public policy conditions requiring the development of a new paradigm to facilitate the development of new transmission facilities, including the accommodation of renewable energy and other generating facilities that may be location-constrained, as well as the construction of new transmission facilities to address reliability needs and economic benefits on a regional basis. Moreover, the proposed revisions to the Tariff 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. Filing Parties state that the proposal: 1) is consistent with Commission policy that costs are fairly assigned among participants; 2) provides adequate incentives to construct new transmission; and 3) is supported by state authorities and participants across the region. They further assert that this filing has been made in full consideration of the October 23, 2009 Order's directives, as well as the recently issued Transmission NOPR.[30] Filing Parties propose to: 1) establish a new transmission project category designated as MVPs, and a corresponding cost allocation methodology; 2) create SNUs, network upgrades that are funded by interconnection customer(s) and also benefit other interconnection customers that are identified as beneficiaries within five years to share the costs of network upgrades on which they mutually rely; and 3) otherwise retain the existing cost allocation for network upgrades needed for generator interconnection projects.[31] Filing Parties state that these revisions represent broad stakeholder consensus, equitably balance the interests of all parties, and will offer the greatest overall benefits for Midwest ISO and its customers.[32]

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[29] Filing Parties July 15, 2010 Filing, Transmittal Letter at 7-11.

[30] *Id.*, Transmittal Letter at 12-15 (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660).

[31] *Id.*, Transmittal Letter at 1-2.

[32] *Id.*, Transmittal Letter at 11.

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27. Filing Parties note that, under the principle of cost causation, 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, but cost allocation is not an exact science where costs and benefits are allocated with exact precision.[33]

28. According to Filing Parties, MVPs will provide regional benefits, primarily through reductions in transmission losses, regional congestion costs, and the region's installed capacity requirement. MVP costs will be recovered through a system usage (i.e., MWh) charge allocated to all load in, and exports from, Midwest ISO.[34] The charge, called the MVP usage rate, will be used to recover the MVP annual revenue requirement from monthly withdrawals, exports, and wheel-through transactions, as described and calculated in proposed Attachment MM of the Tariff. The proposed MVP cost allocation "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."[35] Thus, Filing Parties also state that regional cost-sharing for these projects avoids the disproportionate impacts to native load in prime wind-power development areas and improves the region's ability to attract new generation that fulfills public policy goals.[36]

29. Filing Parties propose that, in order to qualify as an MVP, a project must meet at least one of the following criteria:

- Criterion 1 – [An MVP] must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably

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[33] *Id.*, Transmittal Letter at 12-13 (citing, *e.g.*, *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476-477 (7th Cir. 2009) (*Illinois Commerce Commission*)). In *Illinois Commerce Commission*, the United States Court of Appeals for the Seventh Circuit (Seventh Circuit) granted an appeal challenging the cost allocation for new transmission facilities in PJM. In the challenged order, the Commission determined that the existing rates were unreasonable and should be replaced with a rate that spreads the costs of new facilities at 500 kV and above to the entire PJM region. The court held that a system-wide allocation of future 500 kV and above transmission costs was not supported by substantial evidence.

[34] Filing Parties July 15, 2010 Filing, Transmittal Letter at 2.

[35] *Id.*, Transmittal Letter at 25. Here Midwest ISO contrasts its proposed usage charge with a demand charge.

[36] *Id.*, Transmittal Letter at 3.

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and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP 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.[37]

- Criterion 2 – [An MVP] must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost [R]atio of 1.0 or higher where the Total MVP Benefit-to-Cost [R]atio is described in Section II.C.6 of [] Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.[38]

- Criterion 3 – [An MVP] 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. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.[39]

30. Reflecting the regional nature of the projects, Filing Parties state that projects considered for MVP cost allocation must be included in the transmission planning process. They cannot be network upgrades constructed only because of an interconnection or transmission service request.[40] Further, a proposed transmission project should not contain any transmission facilities listed in Attachment FF-1 of the Tariff,[41] and the total cost of the transmission project must be greater than or equal to the

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[37] *Id.* at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet No. 3451A.

[38] *Id.*

[39] *Id.* at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet No. 3451B.

[40] *Id.*, Transmittal Letter at 22.

[41] Attachment FF-1 includes a list of projects that were excluded from cost sharing during the RECB I proceeding.

lesser of $20 million or 5 percent of the constructing transmission owner's contemporaneously reported net transmission plant. Facilities associated with projects considered for MVP cost allocation must not be in service, under construction, or approved for construction by the Midwest ISO Board prior to July 16, 2010, or the date the constructing entity becomes a Midwest ISO transmission owner, whichever is later. In addition, projects cannot be considered for MVP cost allocation if they include: 1) an underground or underwater transmission line with costs above and beyond the cost of an alternative overhead transmission line providing comparable benefits; or 2) any direct current transmission line, and associated terminal equipment, that is not under the direct functional control of Midwest ISO.[42]

31. Filing Parties state that projects considered for MVP cost allocation must include some facilities operating at or above 100 kV, but the project can also include facilities operating below 100 kV. Lower-voltage facilities will be considered if they are required as part of the MVP. Filing Parties provide the following 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."[43] Thus, while a proposed MVP may only include facilities operating at or above 100 kV, if those facilities will impact facilities operating at or below 100 kV, the costs of mitigating those impacts will be included in the MVP cost allocation.

32. Filing Parties also claim that the MVP cost allocation would not distort the markets, as opposed to the distortions that might result from imposing a charge on generators and import transactions. Although there could be market distortions from the proposed export charge, Filing Parties believe that charging exports is necessary to: 1) avoid providing an undue advantage to external loads that use Midwest ISO's transmission system; and 2) place market participants serving external loads in a comparable position to Midwest ISO loads. Filing Parties acknowledge that Midwest ISO may need to modify the Financial Transmission Right and Auction Revenue Right allocation processes so that the benefits of MVP transmission are similarly socialized.[44]

33. Filing Parties submitted a list of 16 potential starter projects as an illustration of the types of projects that would qualify as MVPs. These starter projects were identified

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[42] Filing Parties July 15, 2010 Filing, Transmittal Letter at 22-23.

[43] *Id.*, Curran Test. at 31. These sub-100kV facilities are referred to as "underbuild" facilities.

[44] Filing Parties July 15, 2010 Filing, Transmittal Letter at 27-28.

through a number of processes: 1) the Regional Generation Outlet Study, a transmission expansion plan developed to facilitate the Renewable Portfolio Standard objectives that eleven out of thirteen Midwest ISO member states have passed or adopted; 2) the "Top Congested Flowgate" and "Cross-Border Top Congested Flowgate" studies; 3) the Narrowly Constrained Area Targeted Study, a transmission expansion planning study intended to identify and mitigate areas of persistent congestion; 4) the Definitive Planning Phase and System Planning and Analysis studies performed during Midwest ISO's generator interconnection process; and 5) an economic and reliability analysis of MTEP Appendix B and C projects developed and studied as part of the traditional Midwest ISO transmission expansion planning process to address future reliability needs.[45] The list of potential MVPs includes transmission lines in every region of the Midwest ISO footprint and represents about $4.6 billion in investment to be developed over the next 10 years. Of the potential MVPs, one is 230 kV, one is 765 kV, and fourteen are 345 kV.

34. Filing Parties performed an analysis of the MVP starter projects and estimate that these projects will deliver between $582 million and $798 million in annual economic benefits starting in 2015 from expected production cost savings, reductions in transmission losses, and a reduction in the region's reserve margins.[46] Filing Parties divide these estimated annual savings into the following categories:

- Between $297 million and $423 million in annual adjusted production cost savings, spread almost evenly across all Midwest ISO Planning Regions;
- Between $68 million and $104 million in annual transmission system loss savings when the starter projects are put into service;[47] and
- Between $217 million and $271 million in annual reductions of the region's reserve margin is realized due to load diversity.[48]

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[45] Projects in MTEP Appendix C are proposed upgrades for which a need has not been established but which may be beneficial. Once an upgrade has been identified as a potential solution to a reliability problem or potentially economically beneficial project, it is moved into MTEP Appendix B. All proposed projects start in MTEP Appendix C.

[46] Filing Parties July 15, 2010 Filing, Curran Test. at 26.

[47] This estimate is associated with an annual reduction in transmission losses of approximately 1,500,000 to 2,000,000 MWh. *Id.*, Curran Test. at 24.

[48] *Id.*, Curran Test. at 26.

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35. Filing Parties note that higher production cost savings and savings in deferred capacity investment could add billions of dollars to this indicative estimate of the MVP starter projects in the long run.[49] For example, Filing Parties estimate that the annual production cost savings, listed in the first bullet above, increases to between $400 million to $1.3 billion by 2025.

36. Filing Parties state that related benefits quantified from the MVP starter projects include annual potential load cost savings ranging from $14 million to $984 million in 2015 and negative $19 million to $2 billion in 2025.[50]

37. Filing Parties indicate that further benefits may be realized, although these further benefits were not quantified from the MVP starter projects. They state that even a relatively small reduction of 0.5 percent in reserve requirements would result in a deferral of about 500 MW of capacity investment, saving approximately $500 million.[51] Filing Parties also indicate that a transmission system that is more resilient to contingencies, and thus more reliable, should reduce wind facility curtailments by approximately 25 percent in the east region.[52] Moreover, Curran states that those benefits do not include real, but harder to quantify, benefits of satisfying regional public policy objectives and ensuring regional reliability.[53]

38. By contrast, Curran states that the estimated annual revenue requirement for the starter projects is $675 million.[54]

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[49] *Id.*

[50] *Id.*, Lawhorn Test. at 13-14. Lawhorn explains that load cost is the cost that load serving entities pay to purchase energy to serve their load served; it is the MW of load multiplied by the load-weighted LMP. Lawhorn states that 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.

[51] *Id.*, Curran Test. at 25.

[52] *Id.*, Transmittal Letter at 16-17, Lawhorn Test. at 12-14.

[53] *Id.*, Curran Test. at 26-27.

[54] *Id.*

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39. In addition to estimating the savings that the potential starter projects would provide (mentioned above), Midwest ISO studied the regional usage of certain facilities including those studied in the Regional Generation Outlet Study. Midwest ISO defined local usage as delivering energy from local facilities to local load, and any other usage as regional.[55] It used a sample of 2.5 percent of hours distributed throughout the year (i.e., 219 hours) to approximate the annual load duration curve. Further studies were completed on various classes of transmission facilities proposed in the long term transmission plan, including over two hundred 345 kV and 765 kV facilities. Midwest ISO describes these as "the best available representation of the type of future transmission facilities that would likely be categorized as MVPs."[56] The mileage-weighted analysis showed that at least 80 percent of the usage of these facilities would be regional.[57]

40. In addition to proposing the MVP category, Filing Parties propose to create SNUs. If a project is designated as an SNU, the interconnection customer that originally funded such project that is found to benefit other interconnection customers that come later would be eligible for contributions from the late-coming interconnection customers. To be considered for SNU cost sharing, a project must: 1) be identified in a generator interconnection agreement that is effective after July 15, 2010; 2) 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 the upgrade as being eligible for contribution; and 3) have been determined by Midwest ISO to benefit a later-interconnected interconnection customer.[58]

41. Filing Parties claim that, with the introduction of the MVP and SNU classifications, the current burden on interconnection customers of paying for network upgrades will be significantly reduced. Filing Parties acknowledge that those network upgrade projects that are required solely for generator interconnection will continue to be subject to the existing cost allocation methodology. According to Filing Parties, "[i]nterconnection [c]ustomers that choose to site their projects in areas of the system that require transmission reinforcement, but are consciously outside [of] the areas where

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[55] *Id.*, Curran Test. at 28. Midwest ISO provided no further explanation of the term regional, though Criterion 2 does specify that economic benefits must accrue to multiple pricing zones. *Id.*, Transmittal Letter at 21.

[56] *Id.*, Curran Test. at 28. Of the fifteen proposed starter projects, one is 230 kV, one is 765 kV, and 13 are 345 kV.

[57] *Id.*, Curran Test. at 27-28.

[58] *Id.*, Transmittal Letter at 31-32.

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generator access will be improved by MVPs, will cause and properly should bear nearly all [of] the costs of Network Upgrades needed in these areas to enable their reliable interconnection to the system . . ."[59]

42. As Filing Parties explain, the SNU designation is meant to solve the "first mover" problem that results from the "lumpiness" of transmission upgrades. This problem occurs when an Interconnection Customer (Generator A) is required to fund a network upgrade, and then interconnection customers (Generators B and C) come soon and benefit from the network upgrade funded by Generator A. Transmission facilities are not custom built, so an upgrade generally provides more capacity than is immediately needed (in this case, enough for Generators A, B, and C).[60] The SNU designation builds on the Common Use Upgrade already in place in the Tariff. The Common Use Upgrade allows several known beneficiaries of a network upgrade to share the costs of these upgrades in advance. The SNU expands this to assign costs to beneficiaries who were not known at the time of the upgrade.[61]

43. Filing Parties request waiver of the prior notice requirement to permit the proposed Tariff revisions to become effective on July 16, 2010. Filing Parties request that the Commission act on the filing during or prior to the Commission's December 16, 2010 meeting.

III. <u>Notice of Filing and Responsive Pleadings</u>

44. Notice of Filing Parties' filing was published in the *Federal Register*, 75 Fed. Reg. 43,961 (2010), with interventions and protests due on or before September 10, 2010.[62] Notices of intervention and motions to intervene were filed by the entities listed in the appendix to this order. The entities that filed protests and comments, and answers, are also listed in the appendix. The party abbreviations listed in the appendix will be used throughout this order.

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[59] *Id.*, Transmittal Letter at 4.

[60] *Id.*, Laverty Test. at 5-8.

[61] *Id.*, Transmittal Letter at 38.

[62] *See* Errata Notice issued on July 20, 2010 in this docket.

IV. Procedural Matters

45. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2010), the notices of intervention and the timely, unopposed motions to intervene serve to make the entities who filed them parties to this proceeding.

46. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2010), the Commission will grant all of the late-filed motions to intervene given the parties' interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

47. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2010), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers because they have provided information that assisted us in our decision-making process.

V. Substantive Matters

48. In this order, the Commission finds that the proposed MVP process is just and reasonable and accepts it for filing subject to modifications. We expect the functional approach to MVP selection, as reflected in the MVP criteria, to allow Midwest ISO and its members to achieve a number of goals at one time: 1) to identify transmission projects that will benefit the grid and that may also satisfy documented energy policy mandates or laws; 2) to ensure thorough, transparent consideration of the many factors that will determine which transmission projects should receive regional cost allocation; 3) to allow Midwest ISO flexibility to move forward MVPs to maximize benefits within and across the region; and 4) to further progress toward the goal of facilitating efficient regional transmission planning.

49. However, as part of our acceptance, we will require Filing Parties to make two compliance filings and to submit ongoing annual information reports. In the first compliance filing, due within 60 days of this order, we direct Filing Parties to: 1) state in the Tariff that they will review MVPs on a portfolio basis; 2) revise the Tariff to ensure that the MVP usage rate is not applied to export or wheel-through transactions that sink in the PJM region; 3) provide an explanation as to how the proposed Tariff language relating to Monthly Net Actual Energy Withdrawal and Demand Response Resources and Emergency Demand Response resources is consistent with the rate design objectives stated by Filing Parties, and why it does not result in double netting; and 4) clarify that the divisor of the MVP usage charge in Attachment MM reflects the MWhs of grandfathered service provided by each transmission owner to reflect an allocation of the costs of MVPs recovered under grandfathered agreements. In the second compliance filing, due on or before June 1, 2011, we direct Filing Parties to describe what changes to Midwest ISO's allocation of congestion rights are necessary to reflect the allocation of MVP costs. We further require Midwest ISO to file ongoing annual informational reports

with the Commission describing the selection of MVPs, including the achievements and shortcomings of the MVP selection process, after each full planning cycle has been completed.

50. In addition, we will accept Filing Parties' proposal to make permanent the generator interconnection cost allocation methodology that the Commission conditionally accepted on an interim basis in its October 23, 2009 Order. In accepting this provision, the Commission understands that generator interconnection customers will be required to shoulder 90 percent or 100 percent of the network upgrade costs associated with their interconnection requests; however, the Commission expects that the magnitude of these costs can be significantly mitigated as MVPs are approved and added to Appendix A of the MTEP.

51. Finally, we will accept Filing Parties proposal to allow late-coming interconnection customers who benefit from network upgrades built by an earlier interconnection customer to pay a portion of the costs of the upgrades that qualify as SNUs. By accepting this provision, the Commission expects that the financial burden on first-mover interconnection customers will be further reduced.

A. Demonstration of Benefits Being Commensurate with Costs

52. Under Filing Parties' proposal, projects will be eligible for MVP cost allocation if they meet one of the three criteria discussed above, are selected through the MTEP planning process, and meet the minimum cost and voltage levels specified above. The MTEP process will be open and transparent and allow for stakeholder participation. MVPs will be assembled into a portfolio in the MTEP process to be analyzed for MVP cost allocation, with a goal of providing a regional solution that globally benefits all users of the Midwest ISO transmission system.

53. MVP costs will be allocated system-wide to Midwest ISO load, exports, and wheel-through transactions based on actual energy usage. To support Filing Parties' proposal, Midwest ISO performed a series of economic analyses based on a set of 16 potential MVP starter projects. These studies project benefits in 2015 of $582 million to $798 million.[63] In addition, Midwest ISO performed a transmission usage study on over two hundred 345 kV and 765 kV facilities identified through the Regional Generation Outlet Study. This analysis showed that system usage of these facilities would be 80-percent regional.[64]

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[63] Filing Parties July 15, 2010 Filing, Curran Test. at 26.

[64] *Id.*, Curran Test. at 28.

54. In this order, we accept Filing Parties' proposal for filing, and grant waiver of the 60-day notice period to make it effective on July 16, 2010. We find that Filing Parties have demonstrated that their proposed package of processes, which together will lead to the approval of MVPs for regional cost sharing, and will appropriately match the regionally-allocated costs of MVPs to the benefits of those projects. Specifically, we find that the three criteria will determine that each individual project will have regional benefits, and that the portfolio approach to project selection ensures that those benefits will be widely spread around the Midwest ISO region. We will require Midwest ISO to make a compliance filing that includes the portfolio approach to project selection in its tariff, and we will also require a series of informational reports that will allow us to monitor, going forward, the function and effectiveness of the MVP process.

55. We disagree with arguments that we should change the three major criteria, the voltage requirements, or the minimum $20 million cost threshold for including a project as an MVP. We find that the Filing Parties' proposal will work alongside, rather than subsume, existing cost allocation and generator interconnection processes. Filing Parties have justified their proposal to continue the existing cost allocation for generator interconnection-related network upgrades, and we approve their proposal to maintain a 10 percent reimbursement to the generator for the costs of such projects. We also find that Filing Parties' proposal to share the costs of Shared Network Upgrades among first-moving and later-coming generators is just and reasonable.

56. Finally, we approve the MVP Usage Rate as a just and reasonable means of recovering the costs of MVPs. Due to existing contractual obligations, including seams elimination between Midwest ISO and PJM, we decline to apply this rate to exports to PJM, or to grandfathered agreements within Midwest ISO.

1. Comments

a. General

57. Acciona, Alliant, ATC, AWEA-WOW, Edison Mission, E.ON, Fresh Energy, Gamesa, Iberdrola, Indiana OUCC, Michigan Commission, MidAmerican, Midwest TDUs, Minnesota Commission-Minnesota Security, NextEra, NIPSCO, SummitWind, and Wisconsin Electric all comment in general support of the filing, while expressing limited concern over specific aspects of the proposal. Acciona states that MVPs providing long-term, region-wide benefits fit the description in the recent Commission Transmission NOPR of projects worthy of region-wide cost allocation.[65]

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[65] Acciona Comments at 5-6 (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 156).

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58. ATC states that, while transmission lines built to support efficient renewable energy mandates will be regionally beneficial, Midwest ISO currently does not have a cost-sharing mechanism in its Tariff that adequately reflects the regional value of these transmission facilities. Because of this, ATC recommends that the Commission approve the MVP proposal, stating that the cost of constructing transmission projects that provide regional benefits and that assist in fulfilling specific public policy mandates should be shared regionally to reflect the value of the benefit achieved.[66]

59. Iberdrola also states that the instant proposal would specifically identify those facilities that enable location-constrained renewable resources (typically in western Midwest ISO) to provide energy to meet state renewable portfolio standard requirements. Eleven of thirteen Midwest ISO states have already adopted renewable portfolio standards or clear renewable energy goals for their incumbent utilities, and the Midwest ISO Regional Generation Outlet Study developed a transmission expansion plan to facilitate achievement of the state renewable portfolio standard objectives.[67] Thus, Iberdrola states, the MVP proposal will provide broad, regional benefits throughout Midwest ISO's footprint. Iberdrola also argues that Midwest ISO provided sufficient analysis to support that claim. Further, Iberdrola states that the Commission considers whether a cost allocation proposal provides adequate incentives to construct new transmission; Iberdrola believes that the MVP proposal will in fact facilitate the construction of transmission facilities.

60. Several parties request modification to one or more of the criteria that would determine which projects qualify as MVPs. Where protestors request specific revisions to the criteria, they are listed below. Certain protestors object to the MVP criteria in general or to the cost allocation proposal. MISO Northeast Transmission Customers argue that nothing in Midwest ISO's proposal will limit the amount of transmission built to what is actually needed, as opposed to what western states in Midwest ISO may desire. MISO Northeast Transmission Customers state that the proposed criteria do not compel any investigation of possible less-costly alternatives to proposed MVPs.[68] Joint Protestors request that the Commission require Midwest ISO to develop a narrower, more defined stakeholder methodology for assessing the regional costs and benefits (i.e., SPP's Highway/Byway methodology).[69] Indiana Commission and MPPA argue that the

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[66] ATC Comments at 4.

[67] Iberdrola Comments at 11.

[68] MISO Northeast Transmission Customers Comments at 26.

[69] Joint Protestors Comments at 8-9.

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Commission should direct Filing Parties to revise the proposed Tariff language such that a proposed MVP would have to demonstrate that it provides benefits to a minimum of three or more pricing zones so that a project receiving regional cost sharing provides regional benefits.

61. IPL states that the MVP proposal could result in shifting costs to the rest of the footprint without the promise of quantifiable and approximately equal benefits for IPL and others. IPL states that the Commission may consider requiring Midwest ISO to impose a cap on costs that can be shifted to certain ratepayers as a result of implementation of its cost allocation proposal and notes an instance in which the Commission affirmed that a cost-shift cap was warranted for a transition period.[70]

62. IPL also argues that the MVP proposal must be modified to limit the number of projects that can be approved and to include a budgeting mechanism for those projects. IPL states that there is now no such limit on the number of projects that can be built and, without such limits, load-serving entities cannot know how much they will be forced to pay. Thus, asserts IPL, the Commission should impose a budgeting process such that projects and costs can be limited or reviewed in some manner. IPL argues that it is the Commission's duty to protect consumers, and in approving a plan that favors investors with no protection for consumers, it is abandoning its traditional role under the FPA. IPL states that, while the argument may be made that consumers benefit because of increased reliability or increased access to markets, the utility industry has always recognized that there has to be some balance between building adequate facilities and minimizing costs to consumers. IPL asserts that approving this plan without a budget mechanism discards that traditional balance and is not in the public interest.[71]

63. Illinois Commission states that the unrestricted planning authority of Midwest ISO, in combination with the open-ended definition of benefits for the Total MVP Benefit-to-Cost Ratio, may induce overinvestment in transmission capacity, "especially

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[70] IPL Comments at 31 (citing *Cal. Indep. Sys. Operator, Corp.*, Opinion No. 478, 109 FERC ¶ 61,301 (2004), *order on reh'g*, 111 FERC ¶ 61,337 (2005) (June 2, 2005 Rehearing Order)).

[71] *Id.* at 32-33.

given the low risk and high rate of return on transmission infrastructure and the risk shifting to load that the Commission has allowed under Order No. 679."[72]

64. Others make very specific requests. Michigan Commission asks the Commission to establish a rebuttable presumption that only the initial projected cost expectation for a project is subject to the cost recovery mechanism, so that the applicant must demonstrate that cost overruns are just and reasonable and could not have otherwise been anticipated.[73]

b. Criterion 1

i. Too Broad

65. Designated PJM Parties, MICH-CARE, Exelon, IMEA, Industrial Customers, Iowa Board, Iowa Advocate, MISO Northeast Transmission Customers, MPPA, and Wisconsin Commission express concern that MVPs are defined in a way that is too broad and/or vague. These parties believe that such vagueness will result in unfettered discretion and/or lead to overbuilding.[74] Industrial Customers believe that Filing Parties' proposal is a fundamental departure from traditional transmission planning principles by building transmission projects based upon pure speculation of generation siting, will lead to wasteful capital investment, and is contrary to the Commission's siting policies of Order No. 2003.[75]

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[72] Illinois Commission Comments at 30. *See Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[73] Michigan Commission Comments at 17.

[74] Industrial Customers Comments at 23-25; MPPA Comments at 10-11. *See also* Vectren South Comments at 4.

[75] IMEA Comments at 4-7. MPPA expresses a similar concern regarding how the use of projected flows from hypothetical resources could result in massive upgrades on facilities that may never see the flows projected in the analysis. To avoid this situation, MPPA recommends that the Commission require Midwest ISO to look at actual loads and at existing and under-construction resource effects in determining which lower-voltage facilities, if any, should qualify for inclusion in a MVP as "underbuild" facilities. MPPA Comments at 12-13.

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66. Commenters ask that Criterion 1 be modified to exclude, or the Tariff language be revised to make more transparent, the determination of which projects will implement public policy. As IMEA understands Criterion 1, projects could potentially qualify merely on the supposition that they will meet future, as yet-to-be-defined public policy mandates. Iowa Advocate states that the proposal fails to include a requirement that the transmission project approved under Criterion 1 is actually needed to fulfill the policy mandate. PSEG Companies and MICH-CARE oppose the proposal's inclusion of a public policy component in the MVP criterion. MICH-CARE believes that the Commission first needs to define such standards for MVPs in the Transmission NOPR and, further, should not accept the proposal until a clear and reasonable bright line has been determined to clearly distinguish between MVPs and other network upgrades because their associated cost allocations are substantially different.

67. Illinois Commission adds that Midwest ISO fails to substantiate its claim that MVPs provide widespread public policy benefits, and further, Midwest ISO does not even define what it means by regional public policy benefits. As Illinois Commission reads it, nothing in Criterion 1 of the definition of MVPs requires that the public policy driver for the MVP be shown to be regional in nature – as evidenced by the fact that the term "multiple pricing zones" used in Criterion 2 and 3 is not even used in Criterion 1.[76]

68. Exelon states that, although justification for Criteria 2 and 3 have obvious metrics (cost benefit analyses and NERC reliability standards), there is no such obvious metric for transmission projects meant to satisfy public policy initiatives, such as renewable portfolio standards. Exelon suggests that a transmission project should meet Criterion 1 if it minimizes the sum of the above-market costs of the wind generation expected to be built and the cost of the transmission project.[77] MICH-CARE and MPPA argue that Criterion 1 should be modified to require that public policy projects provide delivery of energy to multiple zones, which should be defined as at least three or more pricing zones. Steel Producers claim that Midwest ISO has made no effort to demonstrate that Criterion 1 projects will have any multi-zonal benefits that warrant socializing their costs and state that they do not object to the inclusion of Criterion 1 projects, as long as those projects are subject to an objective, transparent analysis that evidences that costs are reasonably commensurate with the expected benefits.[78]

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[76] Illinois Commission Comments at 20-21.

[77] Exelon Comments at 11-15. *See also* Iowa Board Comments at 11.

[78] Steel Producers Comments at 8-9.

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69. MICH-CARE states that Criterion 1 does not allocate costs that are at least roughly commensurate with the benefits that are expected to accrue because MVP charges will be applied proportionally related to usage across regions, but the benefits of the projects will not be spread in the same manner. MICH-CARE believes that, for a project to qualify under Criterion 1, it needs to show that it would provide a positive benefit and meet the mandates or laws in each pricing zone and sub-region.[79]

70. MPPA also states that the proposal should be modified to explicitly require that Midwest ISO's planning studies demonstrate that 50 percent or more of the projected flow on the lines in a project is sourced from public purpose resources for the project to qualify as an MVP under Criterion 1.[80]

71. Alliant interprets the intent of the proposed Tariff language as being tied to policy mandates that are prevalent and generally consistent within the Midwest ISO region. It recommends that the proposed Tariff language be modified to specifically reflect that policy mandates used as the basis for MVP regional cost allocation treatment be prevalent within a majority of the Midwest ISO footprint for the policy mandate to be the basis for MVP regional cost allocation treatment.[81]

72. Michigan Commission states that projects qualifying under Criterion 1 should be able to deliver energy reliably and economically to support documented energy policy mandates. Where that is not the case, Michigan Commission requests that Midwest ISO should develop a different cost allocation to allow for more equitable sharing of costs to customers for MVPs that would be roughly commensurate with the benefits that they would receive.[82]

ii. <u>Too Limited</u>

73. Other parties find Criterion 1 to be vague but believe that the result will be that the implementation of designating MVPs will be too limited. NextEra believes that Criterion 1 could be interpreted to require a multi-state requirement for transmission projects and believes that the Tariff should be clarified to not have such a requirement. NextEra also states that the Tariff should specify that meeting the substantive requirements under the

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[79] MICH-CARE Comments at 8-10.

[80] MPPA Comments at 10-11. *See also* Vectren South Comments at 4.

[81] Alliant Comments at 13.

[82] Michigan Commission Comments at 11-12.

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MVP criteria is not just a minimum threshold for MVP designation but will in fact cause the project to be designated as an MVP. NextEra also states that the Tariff should not prevent any qualified transmission developer from being able to propose, develop, and own an MVP, consistent with the applicable Midwest ISO procedures for the creation of an MVP.[83]

74. E.ON states that the following qualifier for Criterion 1, "the MVP 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," could unnecessarily preclude or delay the construction of transmission needed to meet state renewable portfolio standards. E.ON requests that the Commission either require Midwest ISO to delete the language or, alternatively: 1) explain how it intends to apply the qualifying language with specific examples and 2) provide additional Tariff language that lists the criteria that will be applied.[84]

75. ITC Companies-Wolverine argue that Criterion 1 should be expanded to include possible future policies, laws such as environmental mandates that affect the use of specific generation sources, and policy mandates related to demand response or smart grid. To be consistent with the Commission's Transmission NOPR, ITC Companies-Wolverine state, Criterion 1 should be revised to expressly provide for the consideration of current and likely future public policy mandates that may drive the need for transmission projects in determining eligibility for MVP status.[85]

76. AWEA-WOW, Midwest Generators, and Oak Creek suggest that there be a rebuttable presumption that network upgrades required for generator interconnection that are rated at or above 345 kV qualify as MVPs.[86] Such a presumption, they say, would provide greater clarity to which generator interconnection network upgrades would see regional cost sharing.

77. MidAmerican further asks that Criterion 1 be modified to provide for projects that meet documented public policy mandates or requirements beyond the energy policy mandates or laws providing for requirements such as no-carbon, low-carbon, or

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[83] NextEra Comments at 15-16. *See also* Integrys Comments at 5-6.

[84] E.ON Comments at 10-12.

[85] ITC Companies-Wolverine Comments at 11-14.

[86] AWEA-WOW Comments at 31; Midwest Generators Comments at 6-7; Oak Creek Comments at 10-11.

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renewable portfolio standards. MidAmerican believes that this addition would provide appropriate incentives to encourage multi-state transmission construction.[87]

78. AMP is concerned that the proposed language may be unfairly limiting and requests that Midwest ISO be directed to clarify whether energy policy laws or mandates adopted by municipal authorities would be relevant for purposes of determining whether a transmission project qualifies as an MVP under Criterion 1. In AMP's view, because municipal utilities are sometimes not subject to state jurisdiction, refusing to recognize municipal laws or mandates could result in a municipal utility being obligated to share in the funding of energy policy mandates or laws adopted by other government entities, while at the same time being the sole funding source for its own energy policies. AMP believes that this potential result would plainly be unjust and unduly discriminatory.[88]

iii. Renewable Portfolio Standards

79. Illinois Commission, IPL, ABATE, Industrial Customers, MISO Northeast Transmission Customers, AMP, Iowa Advocate, MICH-CARE, and Steel Producers object to allocating the costs associated with state renewable portfolio standards to all load-serving entities on a postage-stamp basis because some load-serving entities are not subject to a renewable portfolio standard and should not be responsible for any associated costs. Illinois Commission argues that a reasonable cost allocation for transmission investments related to public policy initiatives, such as state renewable portfolio standards, would be proportional to the costs caused by each load-serving entity to satisfy its individual renewable portfolio standard requirement. It claims that allocating the same amount of costs to all load-serving entities on a postage-stamp basis is not roughly commensurate with the costs that they cause or the benefits that they receive because renewable portfolio standards are not reasonably consistent across all Midwest ISO states.[89]

80. In addition, some states require that their renewable portfolio standards be satisfied using renewable generation within a specific state, and according to Illinois

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[87] MidAmerican Comments at 22-23.

[88] AMP Comments at 14-15.

[89] For example, Illinois Commission states that each megawatt hour of load within a state with a 20-percent renewable portfolio standard causes twice as much transmission capacity as each megawatt hour of load within a state with a 10-percent standard. Illinois Commission Comments at 21.

Commission, these locational requirements can only increase the total cost of transmission needed to deliver renewable energy.[90]

81. IPL argues that the costs of state renewable portfolio standards should be socialized only to the load of those states that have imposed such obligations. IPL notes that Indiana chose to promote the integration of renewable resources consistent with its integrated resource planning program rather than mandating a specific renewable portfolio standard. IPL maintains that the transmission customers causing the expansions are those in states that have enacted renewable portfolio standards and are meeting those requirements with projects that are not located near existing transmission capacity. IPL concludes that allowing states to pass the cost of compliance with their own renewable portfolio requirements onto neighboring or distant jurisdictions would be inconsistent with Commission policy, including its recent order rejecting Midwest ISO's proposed socialization of the costs for operating reserves.[91]

82. ABATE contends that Midwest ISO should not socialize the cost of out-of-state MVPs because, once FirstEnergy withdraws from Midwest ISO and joins PJM in 2011, there will be only three 138 kV lines connecting Michigan utilities to the remaining Midwest ISO members, and the benefits of out-of-state MVPs to Michigan will not be roughly commensurate with the socialization of costs advocated by Midwest ISO.

83. MISO Northeast Transmission Customers argue that Midwest ISO's MVP proposal forces Michigan electric customers to subsidize out-of-state renewable projects from which they can, at best, receive a very limited benefit. According to MISO Northeast Transmission Customers, Michigan is the only state in Midwest ISO that has incorporated a 100-percent in-state siting requirement into its renewable portfolio standard, and Michigan load-serving entities have developed corresponding implementation plans. They argue that the MVP proposal would force Michigan customers to pay for transmission upgrades in other states that will not help Michigan load-serving entities to satisfy Michigan's renewable portfolio standard and that will compete with the development of wind generation within Michigan. MISO Northeast Transmission Customers contend that the MVP proposal requires them to make a much

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[90] Illinois Commission explains that total costs will increase to the extent that siting generation and building transmission would be cheaper in locations other than those dictated by locational requirements. *Id.* at 22.

[91] IPL Comments at 19 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 132 FERC ¶ 61,088, at P 48 (2010) (July 30, 2010 Order)). *See also* Industrial Customers Comments at 28; Indiana Commission Comments at 3; Iowa Advocate Comments at 10; AMP Comments at 13-14.

greater contribution to the costs of MVPs compared to the value of the benefits that they may realize.[92] They maintain that the proposal is inconsistent with cost causation principles because Michigan customers would subsidize projects caused by the higher renewable portfolio standards enacted in other states.[93] MISO Northeast Transmission Customers request that the MVP proposal be revised to designate the MISO Northeast Transmission Customers' region as a unique area such that its ratepayers would fully pay the costs of those MVPs necessary to meet Michigan's renewable portfolio standard but would not pay the costs of any MVPs constructed in other areas.[94]

iv. MVP Selection Process

84. Wisconsin Commission states that the Commission should require a structured process where states, Midwest ISO management and the Midwest ISO Board, Midwest ISO transmission owners, and generation owners work together to identify which projects are MVPs and worthy of the proposed cost allocation treatment with a significant state role in deciding what projects qualify as MVPs. Wisconsin Commission contends that states are the only RTO stakeholders that must balance the competing interests that make up the broad public interest, and state approval and siting are critical steps after any MVP designation is made.[95] Likewise, Michigan Commission states that the Commission could require Midwest ISO to continue its work to revise its Tariff to include a more detailed MVP planning and approval process that would increase the stakeholder

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[92] MISO Northeast Transmission Customers Comments at 14 (citing MISO Northeast Transmission Customers Comments, Dotterweich Aff. at 4-13). The Dotterweich Affidavit states that, of the $4.1 billion in MVP starter projects listed by Midwest ISO, only the $510 million Michigan Thumb Project is located inside of MISO Northeast Transmission Customers' region. *Id.*, Dotterweich Aff. at 12.

[93] MISO Northeast Transmission Customers note that, while Michigan mandates that renewable resources provide 10 percent of their energy by 2015, Illinois and Minnesota require 25 percent by 2025, and Missouri requires 15 percent by 2021. *Id.* at 8 and 14, n.31.

[94] To effectuate their request, MISO Northeast Transmission Customers suggest specific language for Midwest ISO to incorporate into its Tariff. *See id.* at 15, n.33.

[95] Wisconsin Commission Comments at 8-9.

participation and review to ensure that MVPs are the most reliable and cost effective projects available in the short-term and the long-term.[96]

85. Illinois Commission argues that no process exists for a state to assess the reasonableness of facilities proposed to be built in other states within Midwest ISO. Nevertheless, each state will be required to bear its energy load-ratio share of MVP costs. Illinois Commission contends that the Commission cannot permit such an omission to stand. At a minimum, Illinois Commission recommends that the OMS Board have the opportunity to review and decide on Midwest ISO staff's proposals to move transmission projects with shared costs into MTEP Appendix A, prior to action by the Midwest ISO Board.[97]

86. According to OMS, Midwest ISO stated in its August 25 Planning Advisory Committee that it has no intention of moving MTEP projects from Appendix B to Appendix A on its own. OMS states that Midwest ISO expects that all such projects will be at the request of a transmission owner. OMS states that recent Commission decisions regarding the right of first refusal,[98] as well as its recent Transmission NOPR, could make the planning process more complicated as multiple transmission owners file for, and vie for, similar or the same transmission projects. OMS claims that Midwest ISO will need to develop procedures for how this new planning paradigm will work. At a minimum, OMS states that states will need to get more involved in the transmission planning processes at their host utilities, at merchant transmission construction projects, and at Midwest ISO. For example, OMS is interested in overseeing the need for MVPs and in ensuring the consistency of forecast methods and other types of analyses.[99]

87. IPL states that the first flaw related to the proposed cost allocation criteria is that a project need only meet one of the three criteria. Thus, IPL claims that it is possible that a project could be approved as an MVP and not have gone through the MTEP process. IPL

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[96] Michigan Commission Comments at 18. *See also* Indiana OUCC Comments at 4.

[97] Illinois Commission Comments at 44-45.

[98] OMS Comments at 13 (citing *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010); *Central Transmission, LLC*, 131 FERC ¶ 61,243 (2010)).

[99] *Id.* at 13-14.

states that all projects that qualify for regional cost sharing should have to pass through the MTEP process.[100]

88. MISO Northeast Transmission Customers state that, although Midwest ISO proposes that MVP designation will be made through the MTEP, the transmission planning stakeholder process is insufficient to ensure that the costs imposed as the result of the inclusion of MVPs are just and reasonable for all Midwest ISO transmission customers.[101] In particular, MISO Northeast Transmission Customers state that the process for obtaining MVP designation does not reflect the goal of cost-effective transmission planning and includes a stakeholder review process that is merely advisory.[102]

89. OCC is concerned that transmission projects that do not provide substantial benefits will be approved as MVPs and points to the postage-stamp cost recovery of MVP costs in encouraging certain stakeholders to attempt to qualify transmission projects as MVPs to shift costs from themselves to consumers.[103] In order to prevent this, OCC requests Commission action to ensure that consumers have consistent presence and participation in the Midwest ISO stakeholder process. OCC suggests that this directive be fulfilled by a Midwest ISO-funded organization with an executive director who attends significant Midwest ISO meetings and meetings of interest to consumer interests. OCC claims that this director would serve as both a point of contact and representative for consumer advocates.[104]

90. IPL states that, in Order No. 890, the Commission stated that it "cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory

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[100] IPL Comments at 34.

[101] MISO Northeast Transmission Customers Comments at 25.

[102] *Id.* at 25-26. They also argue that, because of the proposed socialization of MVP costs, to meaningfully participate in the MTEP process transmission customers will be forced to develop expertise and knowledge of systems far away from their home systems and will be forced to staff and participate in planning meetings far beyond their current levels.

[103] OCC Comments at 9-10.

[104] *Id.* at 10-11.

manner."[105] Accordingly, IPL states that, to "limit the opportunities for undue discrimination," the Commission required all RTOs to amend their tariffs to provide for a "coordinated, open, and transparent transmission planning process."[106] IPL claims that the Commission also clarified that openness meant that transmission customers and other stakeholders should be part of the process.[107] IPL states that, if the Commission has concerns with the MTEP process, then the solution is to implement targeted reforms to the MTEP process but not to allow for a complete sidestepping of such process. IPL states that the Commission should reaffirm the vitality of the MTEP process and require all MVPs to qualify through it. Thus, IPL recommends that the Commission clarify that, in any place where the July 15 Filing refers to the Midwest ISO transmission planning process or a similar variant, the parties should refer specifically to the MTEP process.[108]

91. NextEra states that it appears that the identification, designation, and construction of MVPs will depend on how the Midwest ISO transmission planning process unfolds at any given time. NextEra argues that Filing Parties' proposal provides little information on how this will occur, stating only that "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."[109] NextEra states that there are numerous unresolved questions about how the transmission planning process will proceed with regard to MVPs, including how Midwest ISO and the Planning Advisory Committee will address the creation of MVPs and in particular how Midwest ISO and stakeholders participating in the transmission planning process would apply their discretion in formulating an MVP or determining whether a given transmission project might be an MVP.[110]

92. Finally, NextEra states that the planning process needs to be sufficiently forward-looking to meet reasonably expected requirements, which helps guard against undersized

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[105] IPL Comments at 34 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422).

[106] *Id.* at 35 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 435).

[107] *Id.* (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 440).

[108] *Id.*

[109] NextEra Comments at 13 (citing Filing Parties July 15, 2010 Filing, Transmittal Letter at 20).

[110] *Id.*

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facilities. In addition, NextEra states that the Tariff should specify that meeting these substantive requirements is not just a minimum threshold for MVP designation but will, in fact, cause the project to be designated as an MVP, provided that other requirements are also met. NextEra argues that there should not be any discretion for decision makers in Midwest ISO's transmission planning process to deny a project MVP status, unless the applicable transmission needs are met through another MVP or another transmission project paid for through the same or substantially similar means.[111]

93. Midwest Generators state that it is essential that there be a defined time frame for completing the process under which MVPs are evaluated and designated as part of the Midwest ISO transmission planning process.[112] They argue that a known and approved plan, completed in a reasonable period of time, would lower timing risks and improve the ability of generation developers and other market participants to engage in their own planning and project development activities. Thus, Midwest Generators state that the Commission should require Midwest ISO to establish and adhere to specific deadlines that neither preclude meaningful stakeholder involvement nor otherwise threaten to impair the process for making classification decisions.[113]

94. Finally, AWEA-WOW ask the Commission to urge Midwest ISO to move the first set of starter projects forward for identification as MVPs in the 2011 MTEP process and no later than the 2012 MTEP.[114] Midwest Generators, Iberdrola, and Oak Creek make similar requests,[115] and Iberdrola also asks that the first annual report detail Midwest ISO's efforts to meet this goal.[116] AWEA-WOW also ask that the Commission encourage Midwest ISO to assign or hire adequate staffing resources to expeditiously move these projects toward construction.[117]

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[111] *Id.* at 15-16.

[112] Midwest Generators Comments at 7.

[113] *Id.* at 7-8.

[114] AWEA-WOW Comments at 29.

[115] Iberdrola Comments at 25; Midwest Generators Comments at 8; Oak Creek Comments at 11.

[116] Iberdrola Comments at 25.

[117] AWEA-WOW Comments at 29.

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v. Michigan Thumb Project[118] and Out-of-Cycle Review

95. Several parties provide comments on a specific project, the Michigan Thumb Project. This project was recently approved by the Midwest ISO Board in an out-of-cycle MTEP proposal on August 19, 2010. Should the Commission approve the MVP proposal to be effective July 16, 2010 as proposed, this project would be one of the first to qualify under Criterion 1 of the proposal. The project is designated to meet the renewable requirements of the state of Michigan, which requires that its renewable standards be met with in-state resources.

96. Exelon, FirstEnergy, and Vectren South assert that the Michigan Thumb Project is driven solely by Michigan's renewable portfolio standard.[119] Exelon and FirstEnergy argue that Midwest ISO approved the project early, as an "out-of-cycle" request, to satisfy Michigan's 10-percent renewable portfolio standard that will be phased in from 2013 to 2015.[120] FirstEnergy contends that Midwest ISO had no authority under the Midwest ISO Tariff to approve the "out-of-cycle" request to consider the Michigan Thumb Project as an MVP and, thus, violated the filed rate doctrine and Commission precedent. FirstEnergy adds that Midwest ISO recognized in a July 2010 presentation that the Michigan renewable portfolio standard is the impetus for the Michigan Thumb Project.[121] Vectren South argues that Criterion 1 does not include any regional benefit

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[118] The Michigan Thumb Project is rated at 345 kV, is included in the MVP Starter List, and has an estimated cost of $510 million. Witness Moeller states that this project is a result of the State of Michigan Clean, Renewable, and Efficient Energy Act (Act No. 295),which requires identification of existing or new transmission infrastructure necessary to deliver the maximum (4,236 MW) and minimum (2,367 MW) wind energy production potential within the Michigan Thumb region. Witness Moeller states that the proposed transmission project is required to be of appropriate capability to enable the wind potential of the wind energy resource zone to be realized, and wind farms totaling 1,260 MW of generation in the current Midwest ISO generation interconnection queue in the Michigan Thumb region further compel the urgent need to approve a prudent plan that fits all needs. *See* Filing Parties July 15, 2010 Filing, Tab J and Moeller Test. at 21.

[119] *See*, *e.g.*, Vectren South Comments at 4 (citing Filing Parties July 15, 2010 Filing, Moeller Test. at 20-21).

[120] *See*, *e.g.*, FirstEnergy Comments at 38 (citing FirstEnergy Comments, Att. A, Fuerst Declaration at P 58).

[121] *Id.* at 38-39 (citing, *e.g.*, Midwest ISO, July 2010 Out-of-Cycle Presentation at 6, *available at* http://bit.ly/ctFjHb).

component to reflect that some facilities, such as the Michigan Thumb Project, are built to meet energy policy mandates and benefit only the specific zone where the facilities are located.

97. Exelon, FirstEnergy, IPL, and Vectren South argue that the proposed cost allocation for the Michigan Thumb Project is inconsistent with cost causation principles. Exelon maintains that, to the extent that there are production cost benefits outside of Michigan, it is extremely unlikely that any such benefits would be roughly commensurate with the costs imposed on loads as far distant as Missouri or the Dakotas. Exelon notes that transmission cost allocation should follow transmission planning,[122] and it claims that the costs of the Michigan Thumb Project should be socialized only to the extent that there are demonstrated benefits outside of Michigan. IPL argues that no transmission expansion would be necessary but for Michigan's renewable portfolio standard and its requirement that it be met using only in-state resources. FirstEnergy and Vectren South contend that load and exports that derive no benefit from policy-mandated facilities will share in the costs of those facilities, which is inconsistent with cost causation principles.

98. Exelon and FirstEnergy argue that Midwest ISO has not shown that the benefits of the Michigan Thumb Project extend beyond Michigan. They contend that, while Midwest ISO has purported to show cost savings associated with the Michigan Thumb Project, Midwest ISO has not documented that those cost savings go beyond Michigan. FirstEnergy maintains that any cost savings associated with the Michigan Thumb Project will be experienced in Michigan because the wind resources supported by the project would be built in Michigan and loads in Michigan will use that wind energy to satisfy their state renewable portfolio standard.[123] Exelon argues that Midwest ISO has not detailed whether the analysis of the project's cost savings was consistent with existing state laws and regulations (including rate caps) or was based on future anticipated laws and regulations.[124]

99. Similarly, FirstEnergy and IPL argue that Midwest ISO has not shown that a portion of the costs of the Michigan Thumb Project should be allocated to their customers. FirstEnergy states that Midwest ISO intends to assign 11.5 percent of the project's annual costs (nearly $16 million per year) to load in the ATSI zone but only

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[122] Exelon Comments at 9 (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 5).

[123] FirstEnergy Comments at 39 (citing FirstEnergy Comments, Att. C, Farley Declaration at P 48-49).

[124] Exelon Comments at 9, n.16.

16 percent of those costs to load in Michigan.[125] FirstEnergy contends that the ATSI zone has a negligible impact on the transmission system in the Michigan Thumb, noting that the ATSI zone is located in Ohio and Pennsylvania, not Michigan.[126] Therefore, FirstEnergy contends that the ATSI zone did not necessitate the Michigan Thumb Project and will not realize any corresponding reliability benefits. FirstEnergy adds that the ATSI zone will not enjoy any public policy benefits because the zone has no obligation to satisfy Michigan's renewable portfolio standard.[127] FirstEnergy contends that, consistent with cost causation principles, the record must contain substantial evidence showing that the proposed allocation of costs for new MVPs is "roughly commensurate" with the affected customers' respective contributions to the underlying need for lines.[128] FirstEnergy concludes that Midwest ISO has made no such showing.

100. IPL argues that Midwest ISO proposes an unreasonable shift of the cost of the Michigan Thumb Project to IPL's customers. IPL states that Midwest ISO intends to assign IPL 2.7 percent of the Michigan Thumb Project's costs, which would increase IPL's current annual revenue requirement by 19.5 percent. IPL adds that its own studies estimate that the financial impact to IPL of the all projects under the MVP proposal will total $100 million by 2024.[129] IPL contends that Midwest ISO has not shown that IPL's customers necessitated the facilities or would benefit from the Michigan Thumb Project in a manner commensurate with the corresponding cost assignment. IPL concludes that the Commission should reject or substantially modify Filing Parties' proposal.

101. Illinois Commission states that the Michigan Thumb Project illustrates why the Midwest ISO out-of-cycle request process needs to be modified. Illinois Commission points out that section I.B.1.C of Attachment FF states:

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[125] FirstEnergy Comments at 40 (citing July 2010 Out-of-Cycle Presentation at 34).

[126] *Id.* at 39 (citing FirstEnergy Comments, Att. B, Gass Declaration at P 5-6, 16).

[127] FirstEnergy notes that Ohio has a renewable portfolio standard that requires at least half of the renewable resources to be located in Ohio.

[128] FirstEnergy Comments at 40 (citing, *e.g.*, *Midwest ISO Transmission Owners*, 373 F.3d at 1368-1369).

[129] IPL states that its estimate of the cost shifts is "extremely conservative because Midwest ISO has provided no cost estimates of the scope of [MVPs] that may result under the proposal." IPL Comments at 20 (citing IPL Comments, Att. A, Kempker Aff. at 8).

> Out-of-Cycle Review of Transmission Owner Plans: In the event that a [Midwest ISO] [t]ransmission [o]wner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless [Midwest ISO] performs an expedited review of the impacts of the project, [Midwest ISO] shall use a streamlined approval process for reviewing and approving projects proposed by the [Midwest ISO] [t]ransmission [o]wners so that decisions will be provided to the [o]wner within thirty (30) days of the projects submittal to [] Midwest ISO unless a longer review period is mutually agreed upon.[130]

102. Illinois Commission states that the out-of-cycle request provision is short on details, and it is concerned that the out-of-cycle request will be used by transmission owners to circumvent the traditional MTEP process. Thus, Illinois Commission requests that the Commission direct Midwest ISO to revise the current Tariff language so that only reliability projects or projects where transmission owners agree to share the costs of the project are eligible for out-of-cycle review.[131]

c. Criterion 2 and Criterion 3

103. Illinois Commission specifically faults: 1) the inclusion of the "any other" economic or financial benefit category, arguing that this language would allow Midwest ISO to exercise unlimited discretion; 2) that the qualification that a project provide benefits to more than one zone is likely to be satisfied by a project that nonetheless fails to provide benefits commensurate with a postage-stamp cost allocation; and 3) that any meaning to the proposed Total MVP Benefit-to-Cost Ratio test included in the proposed Tariff language is mitigated by the fact that the test does not indicate whether the benefits are distributed across the Midwest ISO region. Finally, Illinois Commission states that the analysis necessary to qualify a transmission project under Criterion 2 would allow Midwest ISO to allocate the costs of a transmission expansion project to load-serving entities based on measurable benefits (that could vary by zone), yet Midwest ISO would still choose to allocate those costs on a postage-stamp basis.

104. IPL suggests that the Commission direct Filing Parties to modify their proposal so that MVP benefits must be shown to occur in a larger portion of the Midwest ISO footprint or to simply allocate the costs to those zones that are demonstrated to benefit from the project.

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[130] Illinois Commission Comments at 46 (citing Midwest ISO Tariff, Fourth Revised Vol. No. 1, Att. FF, section I.B.1.C).

[131] *Id.* at 47.

105. Iowa Advocate opines that Criterion 2 virtually eliminates any rigor that might have been in the benefit-to-cost ratio test because projects are only required to show no losses rather than having to demonstrate benefits. IMEA agrees, asserting that a 1:1 benefit-to-cost ratio does not provide any assurances that there will be any net benefit from a proposed project.

106. Iowa Board states that Criterion 2 and Criterion 3 should be strengthened and clarified to ensure that only projects that are truly regional in nature are designated as MVPs. In addition, Iowa Board states that the benefit-to-cost ratio should be raised from the proposed ratio of 1:1 to 1.25:1.

107. Michigan Commission requests that the Commission reject the use of Criterion 2 as a criterion to qualify as an MVP. In the alternative, Michigan Commission requests that Filing Parties be required to modify the proposed benefit-to-cost ratio test from 1:1 to 1.25:1 to better reflect a project's regional impact as well as making it consistent with the ratio for Cross Border Market Efficiency Projects between Midwest ISO and PJM.

108. Iowa Advocate argues that basing the forecasted benefits for MVPs on a 20-year period makes it likely that the projected benefits would be questionable at best. Specifically, Iowa Advocate points to the Commission's RECB II Order where Midwest ISO explained that, "for a project to be included in MTEP as a [Market Efficiency Project,] it must have a benefit/cost ratio [] that uses a sliding scale to reflect the increased uncertainty of projects with longer construction horizons."[132] Wisconsin Industrials similarly state that the RECB II proceeding recognized that, the farther out the in-service date, the more uncertainty there is regarding the amount of benefits the project will provide. While Wisconsin Industrials understand that some parties believe that the current sliding scale benefit-to-cost ratio test associated with the RECB II proceeding is too rigorous, the answer is not to move so far in the other direction as to make the qualifying threshold too low.

109. ATC seeks clarification that, when a project is being considered under Criterion 3, the cost of the transmission facilities needed to address the reliability issue should not be counted against the economic benefits in considering the benefits-to-cost ratio. When comparing a project's cost to total benefits, ATC avers, the benefits should be compared only to the costs of the "economic" portion of the project (i.e., the costs in excess of the cost of the transmission facilities needed to address the reliability issue).

110. OMS supports Criterion 2 as proposed by Filing Parties. OMS suggests that a benefit-to-cost ratio of 1:1 may not be high enough to ensure that a project will provide

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[132] Iowa Advocate Comments at 11 (citing RECB II Order, 118 FERC ¶ 61,209).

projected benefits but that a ratio of 1.25:1 may be too high and would preclude projects from receiving regional cost allocation.

111. Integrys states that a stringent application of Criterion 2 and Criterion 3 could result in few network upgrades achieving MVP status and thereby undermine the purpose of the MVP cost allocation methodology.

112. Iowa Advocate argues that Criterion 3 essentially adds the same 1:1 benefit-to-cost ratio test required for economic projects to reliability projects and that, due to the uncertainty related to predicting benefits over a 20-year time span, the proposed test does not adequately protect against such uncertainty.

113. OCC believes that Criterion 2 and Criterion 3 should not be allowed to stand separate from Criterion 1. OCC argues that it is necessary to set a high bar for projects to receive postage-stamp cost allocation, such as the proposed MVP methodology. Therefore, OCC requests that the Commission require an MVP to meet both Criterion 1 and either Criterion 2 or Criterion 3.[133] NIPSCO requests that the Commission change the definition of MVPs so that MVPs could be either: 1) projects built for public policy reasons but limited to public policy requirements applicable to Midwest ISO load; or 2) projects that meet both a reliability requirement and an economic benefit (benefit-to-cost-ratio of 1.25:1) for all of Midwest ISO.[134]

d. Voltage Criteria

114. Many parties argue that the proposed 100 kV minimum voltage threshold for a project to be considered for MVP status is too low. AMP also argues that Commission precedent does not support Filing Parties' proposed regional cost sharing of lower-voltage facilities. AMP notes that, in the RECB I Order, the Commission accepted Midwest ISO's proposal for Baseline Reliability Projects that explicitly precluded projects less than 345 kV from receiving a regional cost allocation.[135] Similarly, Illinois Commission believes the 100 kV threshold should be rejected, noting that the lowest voltage line under the control of Midwest ISO is 69 kV, and therefore, a 100 kV

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[133] OCC Comments at 6-7. *See also* Industrial Customers Comments at 19.

[134] NIPSCO Comments at 6-7.

[135] AMP Comments at 10. *See also* Illinois Commission Comments at 32.

threshold would include an overwhelming majority of new transmission facilities in the Midwest ISO footprint.[136]

115. MISO Northeast Transmission Customers believe that the MVP definition should not include "underbuild" transmission in a socialized cost allocation methodology, and they request that the Commission require Midwest ISO to preclude the inclusion of transmission facilities or project component costs below 345kV in the MVP cost allocation.[137] MPPA contends that the limits that presently apply to "underbuild" for Regionally Beneficial Projects in Attachment FF are reasonable and should continue under the proposed MVP criteria.[138]

116. For example, AMP argues that Filing Parties' premise that facilities operating at voltages as low as 100 kV can provide regional benefits is incorrect and that, even if it were correct, Filing Parties have failed to demonstrate that the benefits received by each Midwest ISO zone are at least "roughly commensurate" with the costs imposed on the zone simply by reciting a list of potential benefits that may or may not actually materialize.[139]

117. Michigan Commission states that it believes that Filing Parties' request to include facilities operating at voltages at or above 100 kV does not satisfy the cost causation

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[136] Illinois Commission Comments at 32.

[137] MISO Northeast Transmission Customers Comments at 30.

[138] MPPA Comments at 13-14. MPPA states that Attachment FF currently provides that:

> ". . . [Regionally Beneficial Projects] may include any lower voltage facilities of 100 kV or above that collectively constitute less than fifty percent (50%) of the combined project cost, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required benefit-to-cost ratio threshold for the project as established in [s]ection II.B.1.c, or that otherwise are needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities of the project."

Id. at 14 (citing Midwest ISO Tariff, Fourth Rev. Vol. No. 1, Original Sheet No. 3443).

[139] AMP Comments at 9.

principles articulated by the Commission or the courts, as the usage of these facilities are too local to provide regional benefits commensurate with the expected regional cost allocation. Thus, Michigan Commission requests that the Commission direct Filing Parties to amend the definition of MVP to include a minimum voltage threshold consistent with its neighboring RTOs (300 kV in SPP and 500 kV in PJM).[140]

e. No Direct Cost Assignment of MVPs to Generators

i. Cost Causation and Equity

118. Illinois Commission and Industrial Customers state that generators whose interconnections are enabled by MVPs will benefit from the MVP proposal.[141] Illinois Commission states that the proposal creates undue discrimination among generators and between generators and load. If the MVP proposal is not rejected, and if the interconnecting generators are not allocated a share of the MVP costs directly, then, states Illinois Commission, the Commission should direct Midwest ISO to develop a proposal whereby generators whose interconnection to the system is enabled by an MVP would reimburse, over time, those entities required to bear the burden of the MVP costs. Industrial Customers state that Filing Parties acknowledge that the MVP starter projects have been proposed primarily to facilitate the interconnection of new wind generation facilities. Industrial Customers state that this admission and the proposal's cost assignment would not be permitted under the "but for" standard to interconnect generators and to allocate costs.[142] PJM states that failing to allocate to the generator the

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[140] Michigan Commission Comments at 12-13.

[141] Illinois Commission Comments at 33-38; Industrial Customers Comments at 21-23 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 22).

[142] In this vein, Industrial Customers (Comments at 32-37) argue that there is tension between the present filing, which would exclude generators from paying for MVPs, and a Midwest ISO compliance filing pending before the Commission in Docket No. ER09-1581-004 (Community Wind). In that case, the Commission directed Midwest ISO to remove language that allocated the entire cost of the Brookings Line (a starter MVP in this proceeding), but left open the possibility that a portion of the costs of the Brookings Line could be allocated to these generation projects, commensurate with the portion of the upgrade that would not be necessary but for their interconnection. Acciona argues that, if the proposal is approved, then the Commission should determine in this docket that the Brookings Line qualifies as an MVP (or, if further study is required, at least evaluate the issue in this docket). Iberdrola asks the Commission to clarify that its decision in the Community Wind case is without prejudice to Midwest ISO ultimately determining that the Brookings Line is an MVP and allocating 100 percent of its costs in

(continued…)

costs of transmission enhancements that would not have been needed "but for" the generating project, would have implications for other regions in the country.[143]

119. Hoosier-SIPC and ABATE similarly state that Midwest ISO fails to allocate MVP costs to new renewable generators and, in doing so, grossly misapplies the principles of cost causation.[144]

120. Wisconsin Industrials argue that direct assignment is important because not all new generators will have power purchase agreements and that such entities would nevertheless benefit from the MVPs. By directly assigning the costs to new generators, the costs will be directed to the "right load."[145] Finally, Wisconsin Industrials note the shared network upgrade aspect of the proposal and state that there is no reason why this sharing approach could not be used to cover all costs caused by generator interconnection projects, including those that are now being proposed as MVPs.[146]

121. Hoosier-SIPC and MidAmerican further state that the proposed MVP cost allocation ignores input from the OMS CARP working group and call on the Commission to require Midwest ISO to revise its proposal to assign some costs of the MVPs to generator owners and point to the CARP approach.[147]

122. While some in OMS (Indiana, Michigan, Minnesota, North Dakota, and South Dakota) view the lack of assignment of MVP costs to generators to be balanced by the continuation of 90-percent participant funding, others (Illinois, Iowa, Missouri, Montana, and Ohio) view the lack of assignment of MVP costs to generators to be inconsistent with cost causation principles (i.e., remote generators cause MVP costs and benefit from being able to sell energy and from gaining tax advantages). The state commissions that fault

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accordance with the instant proposal.

[143] PJM Comments at 8.

[144] Hoosier-SIPC Comments at 18-20; ABATE Comments at 4.

[145] *See also* Alliant Comments at 9-11 discussing the importance of the "right load" paying. Alliant states that, if the Commission's decision or Midwest ISO's application of the proposed Tariff exclude charges to exports, a design that includes injection charges to generators merits more consideration.

[146] Wisconsin Industrials Comments at 18.

[147] Hoosier-SIPC Comments at 18-20, Blake Aff. at 19; MidAmerican Comments at 9-11.

the proposal in this regard point to a report by the Midwest ISO Independent Market Monitor in support of the view that generators should be charged for some MVP costs.[148] Thus the "balancing" represented by the proposal, say these parties, remains insufficient: generators should directly bear some of the costs of all network upgrades associated with their interconnections.[149]

123. Iowa Board recommends that the Commission require some allocation of MVP costs to generators, perhaps 10 percent, as a compromise between Midwest ISO's zero-percent proposal and CARP's 20-percent proposal. Iowa Board states, however, that legal and spill-over benefit concerns seem to argue that the access charge would be applied to all generators, in contrast to the Independent Market Monitor's suggestion to apply such a charge mainly to new generators. If the Commission agrees with Iowa Board and imposes such a requirement, Iowa Board believes that the states should have a role in affirming or restricting any election made by a transmission owner to reimburse the MVP costs allocated to generators.[150]

124. MidAmerican asserts that equity considerations and other factors should be considered when evaluating whether to assign MVP costs to generators.[151] MidAmerican faults Midwest ISO witness Ramey's justification that such allocation to generators would produce generation-related market distortions identified in the LECG Report. MidAmerican states that such market distortions are not significant or are at least no more significant than the market impacts of the approach proposed by Filing Parties.[152]

125. Southwestern also objects to generators not being assigned MVP costs, stating that market distortions are precisely the result when those who benefit from a project are exempted from the allocation of the costs of that project. Southwestern argues that allocating these costs to load-serving entities, like that of Southwestern, which has acquired sufficient long-term generation to supply its needs and has made substantial

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[148] *See, e.g.*, Illinois Commission Comments at 34 (citing Illinois Commission Comments at Appendix A, *Presentation of Dr. David Patton Provided to the Midwest ISO RECB Task Force on June 10, 2010*).

[149] *See, e.g.*, OMS Comments at 4-8.

[150] Iowa Board Comments at 3-7.

[151] MidAmerican Comments at 18.

[152] *Id.* at 15-17 (citing the LECG Report).

payments for transmission interconnection and upgrades needed to accommodate this generation, creates market distortions.[153]

126. E.ON, Joint Protestors, and AWEA-WOW support the proposal not to assign MVP costs directly to generators.[154]

ii. Proposal Undermines Efficient Generator Siting

127. AWEA-WOW, MISO Northeast Transmission Customers, Midwest TDUs, and Indiana OUCC are concerned that Filing Parties' proposal may result in inefficient siting of generation.[155]

128. MISO Northeast Transmission Customers argue that Midwest ISO's cost allocation proposal sends a clear, albeit inappropriate, price signal to would-be wind farm developers by removing almost all cost consequences of their siting decisions. MISO Northeast Transmission Customers argue that a more fully-integrated siting and development analysis would consider not only the suitability of a given site from the standpoint of the available wind profile, forecasted production, land use and other environmental considerations and the like, but also the cost and availability of transmission.[156] MISO Northeast Transmission Customers point to the potential to develop significant amounts of wind generation in the Thumb region of Michigan and, absent an MVP proposal like Filing Parties', an analysis of a Thumb wind project versus a North Dakota wind project, for example, would consider a variety of factors, including the respective wind profiles of each locale, transmission losses, and the availability and cost of necessary transmission.[157] MISO Northeast Transmission Customers argue that, for delivery to load in Michigan, it is possible that a Thumb project would look more

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[153] Southwestern Comments at 11.

[154] *See* E.ON Comments at 10; Joint Protestors Comments at 34-36; AWEA-WOW Comments at 22 and 23.

[155] *See*, *e.g.*, MISO Northeast Transmission Customers Comments at 30-33; Midwest TDUs Comments at 6-9; Indiana OUCC Comments at 4.

[156] MISO Northeast Transmission Customers Comments at 31.

[157] *Id.* at 31-32.

attractive than a North Dakota project because of the relative transmission costs, even if the North Dakota wind profile is more attractive.[158]

129. Further, MISO Northeast Transmission Customers argue that the MVP proposal operates more like a tax than a transmission charge and certainly does not act like the price signal that the Commission contemplated at the outset of Midwest ISO's market development.[159] MISO Northeast Transmission Customers contend that Midwest ISO is a transmission operator, and it is not Midwest ISO that should be deciding what kind of generation gets built nor should Midwest ISO decide where that generation gets built. MISO Northeast Transmission Customers assert that Midwest ISO must return to its role as operator of the transmission platform upon which a competitive market can operate instead of biasing the analysis of generation alternatives by deciding that new transmission investment should be treated differently (via socialization) than all other transmission investments.

130. Midwest TDUs argue that exempting generators from MVP costs gives them a strong financial incentive to favor transmission solutions that assume heavier reliance on wind in the western portions of Midwest ISO (with the highest capacity factors), even if it would be more cost effective (taking account of all associated transmission and other costs) to build the generation closer to load.[160] Such generators would then pressure Midwest ISO to designate any transmission facilities needed to deliver their energy to load centers as MVPs.[161] Midwest TDUs state that Midwest ISO's Independent Market Monitor particularly identified the problem of inefficient siting in its comments on Midwest ISO's proposed approach.

131. Lastly, Midwest TDUs state that the one shortcoming of the proposed cost allocation from an efficiency perspective is that the costs of new transmission are not allocated more directly to the *new* generation that is creating the demand for the new transmission. Midwest TDUs contend that this is sub-optimal because it does not allow investors in the new resources to recognize the total costs of their siting decisions.

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[158] *Id.* at 32. *See also* Midwest TDUs Comments at 7 ("properly taking the cost of the associated transmission upgrades into account could result in a very different and more efficient geographic distribution of renewable resources that relies more heavily on local resources with lower total delivered costs").

[159] MISO Northeast Transmission Customers Comments at 32.

[160] Midwest TDUs Comments at 6.

[161] *Id.* at 8.

Therefore, Midwest TDUs maintain that investors will not have efficient incentives to build their new generation in locations that minimize their total entry costs (including the costs of *both* the generation and transmission).[162]

132. Industrial Customers state that a failure to align cost responsibility and cost causation will result in generators having no incentive to discipline their siting decisions and will also impede a proper identification of the most cost-effective generation solutions. This principle applies equally well for a single coal-fired generation facility making tradeoffs in its proximity to fuel and load as it does for large numbers of wind resources in Midwest ISO's interconnection queue. For customers, this results in a "lose-lose" proposition.

133. Wisconsin Electric also calls for MVP costs to be allocated to new generation to incent efficient siting.[163] Wisconsin Industrials and MICH-CARE similarly state that assigning no MVP costs to new generators will result in the lack of a pricing signal for efficient siting and speculative transmission investment.[164]

f. Transmission Studies, Cost Causation, and the *Illinois Commerce Commission* Decision

134. Acciona, ATC, AWEA-WOW, Gamesa, Iberdrola, ITC Companies-Wolverine, Oak Creek, OMS, and Xcel all state that Midwest ISO has presented sufficient evidence to support its claim that MVP-like projects will provide region-wide benefits and therefore should have their costs allocated across the Midwest ISO footprint. ITC Companies-Wolverine state that, under the MVP proposal, cost allocation would be roughly commensurate with benefits received, meeting the requirements of the Seventh

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[162] *Id.* at 6 (citing Summary of Midwest ISO's Independent Market Monitor Comments on Cost Allocation Proposal from June 10, 2010 Meeting, *available at* http://www.midwestiso.org/publish/Document/345da0_1299503ccb2_-7f5f0a48324a/Summary%20of%20IMM%20Comments%20on%20Cost%20Allocation%20Proposal%20from%20June%2010%20Meeting.pdf?action=download&_property=Attachment). Midwest TDUs note that the Independent Market Monitor's comments were received after the May 19, 2010 meeting at which the Midwest ISO Advisory Committee adopted a motion that included the concept of allocating 100 percent of the costs of certain transmission projects to load through a demand charge. *Id.* at 6-7.

[163] Wisconsin Electric Comments at 3.

[164] Wisconsin Industrials Comments at 16-17; MICH-CARE Comments at 7.

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Circuit Court in *Illinois Commerce Commission*.[165] AWEA-WOW and Acciona state that Midwest ISO has shown that the MVP starter projects will reduce congestion, further public policy goals, and reduce production costs across the region. AWEA-WOW note that, since these studies do not quantify all of the benefits from transmission lines, such as a greater ability to meet policy requirements, increased system reliability, improved operating conditions, and a reduction in generator interconnection costs, the overall financial benefits would likely be significantly larger than these estimates.[166] Further, AWEA-WOW note that Midwest ISO studies show that the transmission facilities in the long-term transmission plan show 80-percent regional usage.[167] Xcel states that Commission precedent has established, and the courts have upheld, that the determination of the beneficiaries of transmission facilities, and the allocation of costs to those beneficiaries, need not be precise.[168]

135. Iberdrola argues that, consistent with court and Commission precedent, Midwest ISO does not need to "calculate a specific economic or dollar-for-dollar benefit that any one entity receives as a result of the identification of MVPs."[169] According to Iberdrola, Midwest ISO has shown that the MVP cost allocation assigns costs that are roughly commensurate with the expected benefits, and this meets Midwest ISO's burden. Iberdrola states that the Commission's recent order regarding cost allocation in the Southwest Power Pool (SPP) confirms that Midwest ISO is only required to demonstrate that assigned costs are roughly commensurate with expected benefits over time.[170]

136. OMS states that it is important to note that MVPs have benefits other than making the interconnection of renewable resources easier for renewable energy developers. OMS states that MVPs will also enhance the transmission system and will better enable the interconnection of all sources of new generation, no matter the technology or location. According to OMS, MVPs will increase the transfer capability of the transmission

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[165] ITC Companies-Wolverine Comments at 16-17 (citing *Illinois Commerce Commission*, 576 F.3d at 476).

[166] AWEA-WOW Comments at 17-18.

[167] *Id.* at 19.

[168] Xcel Comments at 12-13 (citing *Midwest ISO Transmission Owners*, 373 F.3d at 1368-69).

[169] Iberdrola Comments at 13.

[170] *Id.* at 14 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 76).

system, which will allow more access to supply choices to deliver energy to a wider range of load, both within and outside of Midwest ISO. OMS states that, on average, this should result in lower delivered-energy costs, since transfer capability enhances the system, not just for a few or some, but for all hours of the day, every day of the year. OMS states that the predicted economic benefits of MVPs can be estimated in terms of load cost savings, adjusted production cost savings, and market congestion benefits.[171]

137. Southwestern emphasizes that it is not opposed to the types of projects that would qualify for MVP cost allocation and is only concerned about what, it states, is a deviation from cost causation principles.[172] According to Southwestern, Midwest ISO ignored traditional cost causation factors in designing the MVP cost allocation and the proposal will only benefit a select group – mainly, generation owners interconnected to the Midwest ISO grid as a result of MVPs and the load-serving affiliates of certain transmission owners.[173]

138. FirstEnergy, Illinois Commission, Industrial Customers, IPL,[174] Iowa Advocate, MICH-CARE, MPPA, NIPSCO, Hoosier-SIPC, Southwestern, and Wisconsin Industrials raise several objections to the MVP proposal: 1) Filing Parties did not provide the actual studies; 2) both the expected benefits and the transmission usage studies are flawed; 3) there is no demonstration that individual pricing zones or load-serving entities will see net benefits; and 4) the starter projects were aggregated to analyze net-benefits rather than analyzed individually. Protestors also dispute the estimated benefits claimed by Midwest ISO and state that Midwest ISO's proposal is not consistent with the Seventh Circuit Court's opinion in *Illinois Commerce Commission*.[175]

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[171] OMS Comments at 3-4.

[172] Southwestern Comments at 5-6.

[173] *Id.* at 10.

[174] IPL states that this proposal is no different from another proposal in which the Commission ordered that Midwest ISO could not allocate 100 percent of the cost of operating reserves region-wide. IPL Comments at 24 (citing July 30, 2010 Order, 132 FERC ¶ 61,088 at P 48).

[175] *Illinois Commerce Commission*, 576 F.3d at 476.

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139. Illinois Commission objects to Midwest ISO's characterization of MVPs as inherently regional and necessarily providing regional benefits.[176] Illinois Commission notes that the OMS CARP and Midwest ISO RECB transmission usage studies that are cited only studied lines rated at 345 kV and above, yet here Midwest ISO proposes to extend the definition of MVPs down to 100 kV.[177]

140. Illinois Commission and IPL object to Midwest ISO not providing the studies on which it bases its claims of region-wide benefits and state that the benefits Midwest ISO claims are vague.[178] Illinois Commission objects to Midwest ISO claiming regional-wide benefits and supporting this claim with empirical estimates that come from sources that are not cited in the July 15 Filing. Illinois Commission states that this means that the accuracy of the estimates cannot be independently verified. Further, Illinois Commission and Hoosier-SIPC state that there is no empirical estimation of how the positive-adjusted production cost savings accrue to planning regions, transmission owner zones, or load-serving entities.[179] Again, with no empirical evidence or cited source of such evidence, Illinois Commission states that it is not possible to verify this claim. Illinois Commission makes similar arguments regarding Midwest ISO's estimated load cost savings, transmission loss savings, decreased need for installed capacity, and ability to integrate more renewable generation.[180] Illinois Commission also argues that the value of Auction Revenue Rights and Financial Transmission Rights must also be included in any calculation of the benefits and costs of a proposed MVP.[181]

141. Industrial Customers agree that the proposed cost sharing is unsupported. They state that Moeller's testimony is unsupported by any evidence. They contend that Lawhorn's testimony shows that load cost savings could be *de minimus* or even negative and provides no evidence that production cost savings, load cost savings, or reduced losses will be distributed region-wide.[182] Industrial Customers assert that the value

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[176] Illinois Commission Comments at 6-7, 13-15. *See also* IPL Comments at 21-22.

[177] Illinois Commission Comments at 8-9.

[178] *Id.* at 6; IPL Comments at 21-22.

[179] Hoosier-SIPC Comments at 3-4.

[180] Illinois Commission Comments at 10. *See also* MICH-CARE Comments at 12.

[181] Illinois Commission Comments at 12.

[182] Industrial Customers Comments at 13-16.

Lawhorn presents for avoided capacity exceeds the estimated costs of new entry that Midwest ISO has requested in other proceedings as well as recent estimates from Midwest ISO's Independent Market Monitor.[183] Regarding Curran's testimony on the reliability benefits accruing from MVPs, Industrial Customers state that such a claim must be supported, not just claimed, as any transmission upgrade can be claimed to have reliability benefits. MICH-CARE disagrees with the argument that the MVP proposal would decrease line losses and believes that Filing Parties should place a detailed analysis to support this claim into the record. It states that the purpose of the MVP proposal is to move energy across longer distances from the west side of the region to the east. MICH-CARE states that MVPs could increase line losses because such losses tend to increase as energy is transported over longer distances.

142. Illinois Commission provides data on five transmission projects identified as possible starter projects and for which there is available load cost savings data, delineated by planning region, from the 2010 MTEP study. This sample, says Illinois Commission, shows that benefits are not spread evenly across the Midwest ISO footprint. In one case, Illinois Commission states that the eastern planning region derives positive load cost savings, while the central and western regions see increases in LMPs. Two other cases show overwhelming benefits flowing to the central region, Illinois Commission states, with the western region seeing increases in LMPs in both cases and the eastern planning region also losing in one case and gaining very little in the other. According to Illinois Commission, in only one of the five cases do the benefits outweigh the costs; taken as a group the costs outweigh the benefits for these five projects. Illinois Commission states that, of the last two, one shows positive benefits to all while the other shows all regions facing increased LMPs.[184] Illinois Commission also presents results for production cost savings that show very different results. Taken as a group, Illinois Commission claims that these five projects result in reduced production costs in all planning regions. Illinois Commission states that, individually, each project results in lower production costs across the Midwest ISO region. Illinois Commission states that the eastern planning region sees decreased production costs in all but one case, and the central and western planning regions do in three of five cases. Illinois Commission argues that, while production cost savings may be a good measure of productive efficiency, it says nothing about how those cost savings accrue to market participants.[185] Illinois Commission argues that the MVP

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[183] *Id.* at 16 (citing Midwest ISO November 19, 2008 Filing, Docket No. ER08-394-007; Midwest ISO August 2, 2010 Filing, Docket No. ER10-2090-000).

[184] Illinois Commission Comments at 14, Table 1.

[185] *Id.* at 15, Table 2. *See also* Hoosier-SPIC Comments at 8 (citing *Illinois Commerce Commission*, 576 F.3d at 476-477).

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proposal would violate cost causation principles and is also prohibited by the FPA and the courts.[186]

143. FirstEnergy protests Midwest ISO presenting a package of starter projects to show that MVPs will be regionally beneficial. The benefits of these projects were aggregated in order to show their benefits, while the projects would need to be approved individually, according to FirstEnergy. FirstEnergy states that Midwest ISO has shown only that this collection of projects, as a group, satisfies the MVP criteria and justifies the regional cost allocation. FirstEnergy contends that the "MVP [p]roposal's cost allocation does not comport with the cost causation principle."[187]

144. Industrial Customers and Iowa Advocate question load growth estimates and other inputs into the expected benefits studies. Industrial Customers state that the load data used by Midwest ISO in its five scenarios used to analyze usage patterns is out of date and therefore unreliable. They state that, in a study commissioned by Midwest ISO, virtually all peak load growth by 2030 was estimated to be mitigated by demand response and energy efficiency improvements.[188] Based on this, Industrial Customers state that it is unreasonable to use Midwest ISO's studies to identify what regions may be expected to receive benefits from such (potentially unnecessary) projects. Iowa Advocate questions the assumption that utilities in the eastern region will purchase such quantities of power from remote sources to justify charging customers throughout the Midwest ISO region for projects of the scope being proposed. It states that the viability of the long-distance transaction concept lies primarily in the possibility that the federal government will adopt legislation that in some manner will result in remote energy becoming cost effective in the east. Yet it is well known that states wish to avoid importing energy into their states, according to Iowa Advocate.[189]

145. Several protestors question the validity of Midwest ISO's transmission usage studies. Protestors state that, in the transmission usage study cited by Midwest ISO, the definitions of "local" and "regional" undermine the premise on which Midwest ISO is

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[186] *Id.* at 47-51.

[187] FirstEnergy Comments at 37.

[188] Industrial Customers Comments at 20-21 (citing Global Energy Partners, LLC, *Assessment of Demand Response and Energy Efficiency Potential for Midwest ISO, available at* http://www.midwestmarket.org/publish/Document/ff748_12aaa1280c5_-7fe50a48324a?rev=1).

[189] Iowa Advocate Comments at 15.

relying to assert the regional nature of MVPs. A flow being regional only means that it spanned at least two pricing zones, something Illinois Commission states is insufficient for claiming that the flow is truly regional. Hoosier-SIPC similarly protest Midwest ISO's definition of regional.[190]

146. Illinois Commission, MPPA, MISO Northeast Transmission Customers, IPL, and Industrial Customers all raise objections to Filing Parties' proposal in light of the *Illinois Commerce Commission* decision. According to Illinois Commission, there are several similarities between the MVP cost allocation proposal and PJM's postage-stamp cost allocation that was rejected by the Seventh Circuit Court. Illinois Commission claims that both proposals seek to allocate the costs of new transmission on a postage-stamp basis, justifying them on the basis that the proposed transmission projects would provide region-wide benefits. Illinois Commission believes that both proposals fail to provide sufficient analysis or evidence to support claims of region-wide benefits.[191] According to MPPA, Midwest ISO erroneously equates benefit receipt with cost causation in its proposal, and Filing Parties fail to support their claim that all MVPs benefit load and that all load benefits in a roughly-equivalent manner. Although MPPA acknowledges that the courts have accepted, to some extent, the notion that beneficiaries are deemed to have caused the cost, MPPA believes that Filing Parties' proposal takes this too far.[192] MISO Northeast Transmission Customers make a similar argument, stating that the MVP proposal fails to meet the cost causation requirement by equating benefits with cost causation and by making unsupportable claims about the alleged correspondence of charges and benefits. Accordingly, they contend that the proposed MVP cost allocation would allow Midwest ISO to assess MVP charges on all load, regardless of the benefits that customers may or may not receive from a specific MVP.[193]

147. IPL states that the MVP proposal is not consistent with *Illinois Commerce Commission* because it is skewed to benefit larger transmission owners. As a smaller transmission owner that is less likely to have projects large enough to qualify for the proposed cost sharing, IPL states, its cost burden would outweigh prospective benefits.[194]

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[190] Hoosier-SIPC Comments at 9.

[191] Illinois Commission Comments at 32-33.

[192] MPPA Comments at 5-9.

[193] MISO Northeast Transmission Customers Comments at 11-15.

[194] IPL Comments at 12-15.

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148. Industrial Customers state that "beneficiary pays" is a well-established principle that Midwest ISO essentially ignores in the MVP proposal. According to Industrial Customers, this model of cost allocation is substantively different from, and results in greater economic efficiency than, cost allocation models that socialize transmission costs, which distort the economic incentives of participants by insulating the beneficiaries from the full costs of a given project. Industrial Customers argue that the MVP proposal socializes costs too broadly, thereby failing to align the allocation of costs with beneficiaries. Specifically, Industrial Customers argue that the MVP proposal dramatically shifts costs to load that are currently allocated to interconnecting generation resources. Industrial Customers state that Midwest ISO's studies do not show that this shift would result in broad, regional benefits.

149. Wisconsin Industrials, Hoosier-SIPC, IPL, MICH-CARE, and MPPA state that Midwest ISO provides no evidence regarding how benefits and MVP costs are commensurate for their loads. Wisconsin Industrials state that Midwest ISO provides no evidence that Wisconsin will be allocated a share of MVP costs that is commensurate with its expected benefits. Based on the MVP starter projects, Wisconsin Industrials expects that the entire state will be allocated 15 percent of the currently-projected $4.6 billion cost, amounting to $686 million, $240 million of which will be paid by Wisconsin's industrial sector.[195] While Midwest ISO presents an estimation of future benefits, Wisconsin Industrials state that Wisconsin rate payers will not see them. First, they state that the savings ranges Mr. Lawhorn addresses are on a footprint-wide basis and fail to reflect savings specifically to the Wisconsin ratepayer. Second, Wisconsin Industrials state that, while specifically identifying the value of the benefits received through the program are not possible, it is possible to conclude that Wisconsin will receive less than the 15 percent in costs that it would be expected to pay.[196]

150. IPL objects to Midwest ISO's statements that MVP benefits will accrue generally across the footprint, while only attributing those benefits to three planning regions. IPL states that, because planning zones are large and encompass many states, it can be the case that in any one zone only some states receive benefits, while all pay. It cites the central planning zone as an example, where Illinois and Missouri each have renewable portfolio standards, but Indiana does not. IPL states that Midwest ISO has the data that show benefits by pricing zone.[197]

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[195] Wisconsin Industrials Comments at 11.

[196] *Id.* at 12.

[197] IPL Comments at 22-24.

151. MICH-CARE states that it is likely that residential customers who live far away from an MVP would receive little or no benefit, yet they would be required to help pay for the project under the MVP proposal. For Michigan, MICH-CARE explains, this is especially acute because of the state's relative isolation from the bulk of the Midwest ISO system.[198] Michigan, MPPA states, will represent approximately 20 percent of the load in Midwest ISO and thus under Midwest ISO's proposal pay approximately 20 percent of the costs of all MVPs. Since Michigan law requires them to rely on in-state renewable resources, MPPA states, it cannot receive such benefits.[199]

2. Filing Parties' Answer

152. Filing Parties explain that the MVP category limits region-wide cost recovery to regionally planned facilities that must provide more than local benefits. Moreover, states Midwest ISO, while any single project can benefit all users by enhancing the integrated regional network, MVPs as a category plainly will provide broad regional benefits, as over time they will enhance all parts of the Midwest ISO transmission system. Filing Parties state that Midwest ISO has made clear to stakeholders that MVPs will be reviewed on a "portfolio" basis, taking into account the synergistic effects of individual qualifying MVPs and approving the set of MVPs that maximize overall regional value. Filing Parties generally respond that if the criteria were more restrictive, the development of regional transmission would be hampered. [200]

153. Filing Parties' explain that Criterion 1 needs to be worded broadly, because it must take into account that laws differ from state to state and could change in the future. Filing Parties' note that 11 of the 13 states in Midwest ISO's footprint have documented renewable portfolio standards. Criterion 1 clearly provides a regional benefit to Midwest ISO that is likely to increase in the future. Even for projects driven primarily by public policy, other drivers (i.e., Criterion 2 and Criterion 3) and benefits will likely be present.

154. In response to E.ON's argument that the language, "in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade," introduces economic and reliability considerations into what should be a pure public policy criterion, Filing Parties' explain that reliability and economic considerations cannot be divorced from analysis of upgrades to the integrated transmission network. They argue that planners are required to consider the impact on

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[198] MICH-CARE Comments at 5-6.

[199] MPPA Comments at 8.

[200] Filing Parties October 18, 2010 Answer at 15-16 and 27.

reliability and the overall value provided by a project, particularly when compared to its alternative.

155. In response to Wisconsin Industrials, Filing Parties clarify that an MVP is not meant to be a substitute for a GIP under Criterion 1. Unlike GIPs, which are driven by interconnection requests, MVPs would be derived from a regional planning process.

156. Filing Parties argue that although not every single state within the Midwest ISO region has adopted a renewable portfolio standard, and those states that do have them have different requirements, the fact that 11 of the 13 states have a renewable portfolio standard represents a broad consensus on the need for renewable resources. Further, Filing Parties also believe that there is reason to expect a federal renewable portfolio standard may be adopted in the near future, which would clearly affect the entire Midwest ISO region. According to Filing Parties, thousands of megawatts of new generating capacity and related transmission additions will be necessary to meet the requirements of these policies, and it would be unreasonable to omit consideration of them from the MVP criteria.

157. Further, Filing Parties claim that even those states without a renewable portfolio standard or that mandate that their renewable portfolio standard requirements be met with in-state resources will derive significant reliability and economic benefits from MVPs, because even MVPs driven by public policy requirements will strengthen and enhance the transmission network. In response to comments singling out Michigan as a state that will not receive MVP benefits and should therefore be allocated little or no MVP-related costs, Filing Parties claim that Michigan is expected to receive substantial benefits from MVPs. Filing Parties point out that the expected production cost savings reported in the Filing are higher for the East Planning Region, which includes Michigan, than for the other two Midwest ISO Planning Regions. As Filing Parties have consistently argued, MVPs will confer system-wide benefits on all users, including Michigan, of the transmission system. Finally, Filing Parties point out that it is reasonable for Michigan to share the costs of other states' MVPs, just as it is reasonable for those states to share the costs of Michigan's MVPs (such as the Michigan Thumb Project).[201]

158. On the process of identifying MVPs, Filing Parties state that Midwest ISO executes its transmission planning process in an open and transparent fashion in accordance with Order No. 890, and that MVPs will move through the same Commission-approved process.[202] They add that Midwest ISO's Commission-approved

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[201] *Id*. at 17-18.

[202] *Id*. at 40.

planning process offers multiple opportunities for all stakeholders, including transmission owners, state regulators and generators, to provide input and feedback on all aspects of a study beginning with planning assumptions through the final results.

159. With regard to the Michigan Thumb Project referenced by multiple commenters, Filing Parties emphasize that, although approval of the project was advanced, it was considered and evaluated by Midwest ISO planners as only one of a group of potential MVPs considered for approval. All of these projects combined form a portfolio of projects that provide public policy benefits for the entire Midwest ISO region. Filing Parties explain that although some projects, such as the Michigan Thumb Project, support certain areas more than others, the entire portfolio of projects is expected to provide regionally distributed benefits.[203]

160. Filing Parties also argue that their proposed benefit-to-cost ratio of 1.0 is appropriate. Filing Parties point out that it is common for benefits to increase and costs to decrease over the life of a project and therefore it is likely that a project will "generate value beyond 20 years, thus a 1.0 benefit-to-cost ratio evaluated over the first 20 years of a project's life provides a sufficient cushion to address any concerns over a benefit-to-cost threshold of 1.0."[204]

161. With respect to the arguments put forward that the MVP criteria do not adequately ensure that benefits are regional in nature, Filing Parties state that qualifying projects will be shown to have quantifiable economic benefits in multiple pricing zones and to provide multiple types of economic benefits.

162. On the purpose of Criterion 3, Filing Parties reiterate that projects that qualify under this criterion will facilitate the development of transmission infrastructure that provides economic value across multiple pricing zones while simultaneously addressing at least one current or imminent violation of a NERC or Regional Entity reliability standard. For example, Filing Parties state that it is appropriate for a project that solves projected NERC violations in multiple pricing zones at a lower annual revenue requirement than the combined annual revenue requirement of multiple, bottom-up reliability projects that would be necessary to address the projected violations individually, to be eligible for regional cost sharing.

163. Regarding the voltage cutoff, Filing Parties state that despite representations made by protestors, 100 kV represents the minimum size transmission facility over which

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[203] *Id.* at 15-16.

[204] *Id.* at 32.

Midwest ISO generally exercises functional control and that it is appropriate for Midwest ISO to evaluate all facilities over which it exercises functional control to determine whether they qualify for MVP cost allocation.[205] Filing Parties also note that irrespective of a project's voltage level, a transmission facility that has been determined by Midwest ISO, through its MTEP process, to provide regional benefits as an MVP should be eligible to receive MVP cost allocation. Filing Parties assert that increasing the 100 kV threshold could cause significant problems. For example, if the threshold were raised to 230 kV and a project operating at a voltage below 230 kV (e.g., 161 kV, etc.) were demonstrated to be the most prudent solution to meet incremental public policy requirements or to enhance regional value, such a project would be unnecessarily and inappropriately excluded from MVP consideration based solely on the higher voltage threshold. Indeed, there are a number of areas within the Midwest ISO footprint where 230 kV transmission is used regionally and provides regional benefits, and where such facilities represent the maximum voltage used to provide transmission service. Thus, "the fact a transmission facility is 'only' rated at 100 kV is not and should not be, in and of itself, determinative of whether the facility provides regional benefits and is appropriately classified as an MVP."[206]

164. Under their proposal, Filing Parties state that MVPs may include upgrades to facilities below the 100 kV minimum voltage threshold (i.e., underbuild) if the MVP results in transmission issues with these facilities that otherwise would not occur but for the MVP facility. Thus, Filing Parties aver, it is appropriate to include these underbuild upgrades within the scope of the MVP as long as upgrades are evaluated and identified in the MVP study process as not being require but for the proposed MVP facility. Furthermore, Filing Parties contend that it would be unjust and unreasonable to assign the costs of the underbuild facilities solely to the local zone where they are constructed,

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[205] *Id.* at 37 (citing Agreement of Transmission Facilities Owners to Organize Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation, Midwest ISO, FERC Electric Tariff, Rate Schedule No. 1, Appendix H (Transmission System Facilities), first paragraph, sub-paragraph no. 1 (Transmission Owners Agreement); Midwest ISO Tariff, Fourth Revised Vol. No. 1, section 1.55 (definition of "Bulk Electric System")). Some 69 kV facilities, which are below the minimum threshold, may be transferred to Midwest ISO's functional control to the extent that they serve transmission functions, but facilities at or below such voltage levels are generally used for local, rather than regional, transmission. However, to the extent that such facilities are required as part of the "underbuild," and thus contribute to regional reliability, they will be deemed part of the MVP facilities for purposes of cost allocation.

[206] *Id.* at 38.

because it is the MVP facility that is causing the need for those underbuild facilities, not the local loads. On the suggestion to create a rebuttable presumption that generator interconnection network upgrades of 345 kV and above qualify as MVP, Filing Parties respond that such a rebuttable presumption defeats the purpose of other MVP requirements.[207]

165. Filing Parties disagree with protestors' arguments that the cost-sharing for the MVP category is not supported by Commission and court precedent, particularly the Seventh Circuit's ruling in *Illinois Commerce Commission.* According to Filing Parties, court and Commission precedent support broad cost recovery where the benefits are broadly shared, which is the case with their proposed cost recovery for the MVP category. Filing Parties' explain that in *Illinois Commerce Commission*, the court advised that the Commission only needed "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with the assigned costs. Furthermore, Filing Parties state, the courts and the Commission have consistently approved rolled-in pricing (i.e., charging all users of the transmission network as opposed to only specific identified users).[208]

166. Filing Parties point out that the Commission recently relied on these precedents to approve SPP's proposed postage-stamp recovery. The same considerations that the Commission relied on to accept SPP's cost recovery (i.e., users of an integrated system change over time and the overriding commonality in the centrally-planned, regionally integrated high-voltage transmission network) support region-wide recovery for the proposed MVPs, Filing Parties state. Filing Parties claim that like the "highway" category in SPP, the new MVP category defines a subset of regionally planned facilities that provide benefits extending well beyond any single zone, enhance the regional integrated network, and provide benefits to all users of that regional integrated network.[209]

167. Filing Parties also take issue with certain protestors' claim that the proposed MVP category is similar to the cost allocation proposal that was remanded in *Illinois Commerce Commission*. Filing Parties believe that the circumstances are quite different

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[207] *Id*. at 63.

[208] *Id*. at 9.

[209] *Id.* at 10-12 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252). In SPP's proposal, projects rated at 300 kV and higher are allocated 100-percent regionally. Projects rated between 100 kV and 300 kV receive 33-percent regional cost sharing and 67-percent zonal allocation.

in this proceeding; most importantly, the court in *Illinois Commerce Commission* found that the Commission had not presented even a rough estimate of the likely benefits to network users or of the contribution that high-voltage facilities would likely make to the reliability of PJM's network. In contrast, Filing Parties point to the substantial evidence they provided in their filing to support the proposed region-wide cost sharing.[210]

168. In response to protestors' criticisms of Filing Parties' estimation of the expected benefits of MVPs, Filing Parties offer several rebuttals. First, Filing Parties answer that each individual MVP should not be viewed in isolation, but as part of a portfolio of projects. Filing Parties state that Midwest ISO made clear to stakeholders that MVPs will be reviewed on a portfolio basis, taking into account the synergistic effects of individual qualifying MVPs, and approving the set of MVPs that maximize overall regional value.[211]

169. Second, Filing Parties state that criticism of the studies used to support the proposal does not undercut the evidence provided by those studies. In response to Illinois Commission's criticism of the definition of "regional," Filing Parties respond that the definition is logical, in that if a local impact is one that occurs where the facility is located, any other must be regional. Further, the definition used is comparable to that accepted in the SPP Highway-Byway proposal where the Commission found that inter-zonal impacts above a certain threshold indicated the level of a facility's support for regional power flows.[212] As to Illinois Commission's objection to a 100kV cut-off, Filing Parties state that using 100kV allows for underbuild and is required under a "but-for" analysis.[213] In response to IPL and others who criticized the Regional Generation Outlet Study, Filing Parties state that the Regional Generation Outlet Study projects are exactly the projects this proposal is aimed at, transmission facilities necessary to meet renewable portfolio standard goals. Further, Filing Parties state that the support provided through the Regional Generation Outlet Study surpasses the amount of information typically provided to the Commission in such cases. And while IPL cites a roughly even split between local and regional use in the central planning sub-region, Filing Parties state

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[210] *Id.* at 12-14.

[211] *Id.* at 15 (citing 2011 Candidate MVP Study Scope of Work Initial Draft at sections 2.2, 2.3 (Sep. 22, 2010), *available at* http://www.midwestiso.org/publish/Document/35f529_12b1fc99e5a_-7f650a48324a?rev=2).

[212] *Id.* at 20 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 73).

[213] *Id.*

that this analysis is mis-applied here, because that study looked at the how the existing transmission system is used, not at how these new facilities would be used.[214]

170. While protestors criticize the production cost study's analysis of savings based on the established Midwest ISO planning sub-regions, arguing that the studies should instead be performed on a zonal basis, Filing Parties answer that the previously approved Midwest ISO Tariff already expressly prescribes cost-benefit analyses for those same sub-regions to determine transmission cost allocations. In response to Industrial Customers' protest that load forecasts used in the studies were too high, Filing Parties note that these forecasts were provided by the load-serving entities. In response to criticism of the estimate of the cost of new entry, Filing Parties reply that $960,000 represents a generic per MW capital cost roughly between that of a Combustion Turbine or Combined Cycle unit. They state that this value is a fair, even conservative, estimate of the capital cost of new capacity given the current Midwest ISO generator interconnection queue.[215] Finally, as the Commission stated in the SPP Highway-Byway Order, Filing Parties state that just because some parties would choose to use different methods or inputs for determining the benefits of MVPs, that does not mean that Filing Parties' methods are unreasonable or should be rejected.[216]

3. <u>Other Answers</u>

171. Designated PJM Parties state that assertions of "public policy" benefits are inadequate to distinguish the benefits of one MVP versus another and to demonstrate how such benefits are distributed among entities within and adjacent to Midwest ISO.

172. In response to FirstEnergy, ITC Companies contend that Midwest ISO's out-of-cycle approval of the Michigan Thumb Project complied with the transmission planning process provided in the Midwest ISO Tariff and business practices manuals.[217] ITC Companies assert that the out-of-cycle review was imperative to allow ITC Companies to submit its siting application and to meet Michigan's renewable portfolio standard, which

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[214] *Id.* at 21.

[215] *Id.* at 22.

[216] *Id.* at 22-23 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 74).

[217] ITC Companies September 27, 2010 Answer at 4-5 (citing Midwest ISO Tariff, Fourth Revised Vol. No. 1, Att. FF, section I.B.1.c, First Revised Sheet No. 3432; Midwest ISO Business Practices Manual No. 20, Transmission Planning, section 7.1.6).

begins in 2013. ITC Companies add that Midwest ISO stakeholders fully participated in the review process for the project.

173. MISO Northeast Transmission Customers agree with commenters' argument that the benefits of the Michigan Thumb Project would be received, primarily, by load within Michigan. For this reason, they state that Midwest ISO should not require load outside of Michigan to pay for the Michigan Thumb Project, and thus, Midwest ISO should not require load in Michigan to pay for MVPs that do not benefit Michigan loads. MISO Northeast Transmission Customers also contend, however, that the Michigan Thumb Project could help load-serving entities outside of Michigan to satisfy their states' renewable energy mandates, since most states do not have in-state siting requirements.[218] MISO Northeast Transmission Customers argue that, if the Commission does not require Midwest ISO to carve out the Michigan Thumb region for MVP cost allocation purposes, the Michigan Thumb Project should remain one of the MVP starter projects because it would satisfy Criterion 1.

174. In contrast, ITC Companies argue that the Michigan Thumb Project would provide regional benefits sufficient to satisfy Criterion 1. ITC Companies claim that the project is not designed solely to meet Michigan's renewable portfolio standard, stating that the out-of-cycle analysis of the project documented that it would benefit the entire Midwest ISO transmission system by reducing load and production costs, avoiding wind generation curtailment, and reducing carbon dioxide emissions.[219]

175. ITC Companies disagree with MISO Northeast Transmission Customers' argument that Michigan should be treated as a separate area for transmission planning and cost allocation purposes. ITC Companies maintain that they fundamentally challenge the scope of Midwest ISO by essentially proposing a separate Michigan RTO. ITC Companies state that such a proposal would necessitate a separate proceeding. ITC Companies also contend that they take too narrow a view of MVP benefits based on a snapshot of the system today and ignore the integrated nature of the transmission grid.

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[218] In particular, they assert that Michigan load-serving entities would need approximately 1,500 MW of the 4,400 MW of potential wind development in the Michigan Thumb region to satisfy Michigan's renewable portfolio standard, leaving the remainder for use by load-serving entities in other states. MISO Northeast Transmission Customers September 27, 2010 Answer at 4, n.4.

[219] ITC Companies September 27, 2010 Answer at 6, n.14 (citing Out of Cycle Project 3168 Project Justification: Michigan Region 4 Thumb Loop (Draft) at 88, 91). ITC Companies add that the project was also evaluated by stakeholders as part of the Regional Generation Outlet Study and, as a result, is considered an MVP starter project.

ITC Companies assert that Midwest ISO serves multiple functions, and entities should not be allowed to enjoy all of the benefits while accepting only some of the attendant obligations. ITC Companies add that carving out Michigan from the MVP cost allocation would balkanize the planning process, which is incompatible with the Commission's effort to strengthen regional planning in the Transmission NOPR.

176. MISO Northeast Transmission Customers claim that Filing Parties' answer did not address the issues raised by their earlier protest. Specifically, MISO Northeast Transmission Customers are concerned that Michigan will not receive benefits commensurate with the costs of MVPs, and that Michigan will be subsidizing the costs of other states' MVPs.[220]

177. In its answer, PSEG Companies believe that, given the likelihood of changes in both public policies and technology that will impact the grid, transmission planning for public policy could actually undermine the reliability benefits that Midwest ISO claims. PSEG Companies also note that, contrary to Midwest ISO's claim in its answer, the addition of wind resources to the grid may actually impede, not promote, reliability. Finally, PSEG Companies note that Midwest ISO in its answer failed to support its claim that economic benefits in the form of lower production costs or lower capacity costs will result from public policy compliance in the form of more renewable generation.[221]

178. MISO Northeast Transmission Customers state that Filing Parties did not provide any clarity to the definition of MVPs. They also claim that Filing Parties' answer is ambiguous and fails to describe how the MVP definition will be applied.[222] E.ON reiterates its concern over the inclusion of Tariff language including reliability and economic considerations in Criterion 1, and argues that, Filing Parties did not sufficiently address E.ON's concerns in their answer.[223]

179. AWEA-WOW respond to protestors' claims that Midwest ISO has not provided sufficient evidence of the benefits provided by MVPs by reiterating Midwest ISO's evidence and providing its own. Using an economic impact model,[224] AWEA-WOW

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[220] MISO Northeast Transmission Customers November 1, 2010 Answer.

[221] PSEG Companies November 2, 2010 Answer at 3-7.

[222] MISO Northeast Transmission Customers November 1, 2010 Answer at 6-7.

[223] E.ON November 2, 2010 Answer at 27-30.

[224] This economic impact model is intended to estimate the magnitude of the job and economic impacts over a period of time due to some economic injection, in this case,

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estimate, among other things, that total economic benefit from the MVP starter projects between 2012-2036, measured in 2010 dollars, is more than $20 billion. Individual states are estimated to receive benefits equal to anywhere from $0.8 billion for Missouri, to $5.6 billion for Michigan. AWEA-WOW also estimates that more than 60,000 jobs will be created for the construction and operation of these facilities. AWEA-WOW also estimates reduced emissions and water conservation.

180. Designated PJM Parties claim that Filing Parties' answer lacks the requisite evidence to satisfy cost causation principles and to establish that the MVP cost allocation proposal is just, reasonable, and not unduly discriminatory.[225]

181. CMTC responds to Filing Parties' statements that MVPs will be evaluated as part of a portfolio. Specifically, CMTC states that the concept of a portfolio approach to evaluating MVPs was only briefly discussed at a stakeholder meeting in September 2010 and, more important, is not actually contained in the instant proposal. CMTC states that, as written, the three criteria must be met by each MVP, not by a portfolio of MVPs.[226] Further, it states that the benefit-cost ratio outlined in the proposal also indicates that MVPs are to be evaluated individually, citing the use of the phrases "a specific Multi Value Project," and "the Multi Value Project."[227] Based on this, CMTC states that it is not reasonable to base any just and reasonableness determination on MVPs being evaluated as a portfolio since this is not proposed by Filing Parties, no matter any statements made in their October 18, 2010 Answer.

182. CMTC also responds to AWEA-WOW's analysis of the economic impact of the MVPs. CMTC states that the benefits shown by AWEA-WOW are general regional benefits that cannot be included in this analysis per the Commission's precedent; the Commission has stated that a statement of generalized system benefits is not enough to

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the building and maintenance of transmission lines and installation and operation of power generation stations. The analysis does not include the impact of the construction of the wind turbines themselves. AWEA-WOW used the Jobs and Economic Development Impact model (JEDI) developed by the National Renewable Energy Laboratories. *See* AWEA-WOW November 4, 2010 Answer at 8-15.

[225] Designated PJM Parties November 2, 2010 Answer at 4

[226] CMTC November 8, 2010 Answer at 5.

[227] *Id*. at 6 (citing Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Second Revised Sheet No. 293).

support cost allocation.[228] CMTC also notes that AWEA-WOW concede that the benefits they calculate are largely speculative and do not demonstrate specific benefits to any particular region or state. CMTC states that "WOW is essentially admitting that all critical inputs and assumptions for the JEDI model are inherently speculative and unfounded," because there is no way to know exactly which of the MVP lines will be built. Thus, according to CMTC, the caveats that are attached to the JEDI analysis nullify any value that could be derived from the JEDI results. Therefore, CMTC states that the JEDI analysis provided by AWEA-WOW has no probative value and cannot be afforded any weight by the Commission.[229]

183. EPSA answers MidAmerican by noting that MidAmerican supported the CARP proposal which would have assigned 20 percent of MVP costs to new and existing generation and that the CARP proposal was ultimately rejected in Midwest ISO's stakeholder process. EPSA states that neither MidAmerican – nor any other party - has supported the assignment of MVP costs to existing generators which EPSA compares to a tax.[230]

184. MidAmerican responds to EPSA that because MVPs are intended to result in a robust interconnected transmission system, and all loads and generators will use and benefit from such a system, it is appropriate to allocate MVP costs to all loads and generators. MidAmerican takes issue with EPSA's characterization of MidAmerican's position as supporting a tax on generators. Rather, MidAmerican believes it is appropriate to allocate a portion of MVP costs to generators, in the same way that MVP costs would be allocated to loads under the proposal of Filing Parties (i.e., allocating MVP costs to all generators cannot be a "tax" if a charge to all loads, that is intended to produce the same result, is an "allocation").[231]

4. Calls for Annual Reporting

185. Several commenters suggest that the Commission monitor the progress made toward identifying MVPs. AWEA-WOW, Alliant, Iberdrola, IPL, Wisconsin Electric, OMS, and OCC suggest that the Commission require Midwest ISO to submit annual

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[228] *Id*. at 8 (citing *Illinois Commerce Commission*, 576 F.3d at 476).

[229] *Id*. at 8-9.

[230] EPSA September 27, 2010 Answer at 3-5.

[231] MidAmerican October 8, 2010 Answer at 3.

reports or performance reviews.[232] Similarly, Integrys suggests semi-annual filings or, in the alternative, semi-annual posting on Midwest ISO's website[233] and, E.ON suggests quarterly filings.[234] Commenters suggest that the reports include information as to the number of approved MVPs and details on the associated cost allocation, the adequacy of the transmission planning process in identifying MVPs and any challenges involved in that process, whether the contingency window is effective, and any issues related to the coordination of the transmission planning process and generator interconnection processes.

186. In addition, AWEA-WOW request that the Commission require Midwest ISO to file with the Commission the approved 2012 MTEP transmission plan to ensure that the set of Starter Projects were approved by the Midwest ISO Board and, if not, the Commission should require an explanation for Midwest ISO's failure to meet those deadlines and should consider requiring changes to the MVP criteria and transmission planning process to address any obstacles to MVP approval.[235] AWEA-WOW also ask the Commission to require Midwest ISO to include in annual informational reports information identifying upgrades approved as MVPs and upgrades directly assigned to generators. AWEA-WOW assert that if necessary transmission construction does not materialize, both the GIP cost allocation methodology and the MVP criteria should be revisited.[236]

187. Illinois Commission also requests the Commission to require that Midwest ISO's annual MTEP report and associated project cost allocations be submitted with the Commission for review and approval under section 205 of the Federal Power Act.[237]

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[232] AWEA-WOW Comments at 29-30, 35; Alliant Comments at 11; Iberdrola Comments at 24-25; IPL Comments at 30-31; Wisconsin Electric Comments at 4-5; OMS Comments at 13-14; OCC Comments at 8.

[233] Integrys Comments at 7-9.

[234] E.ON Comments at 15-16.

[235] AWEA-WOW Comments at 30.

[236] *Id.* at 40-41.

[237] Illinois Commission Comments at 40-45. Illinois Commission argues that Midwest ISO's transmission expansion plan and the associated cost allocations constitute classification[s], practices, and regulations "affecting rates and charges" that are required, under section 205(c) of the FPA, to be filed with the Commission (citing FPA, section 205(c)).

Illinois Commission states that PJM's Operating Agreement requires that each PJM Board-approved regional transmission expansion plan, including the project costs and the identification of parties to which costs are allocated, be filed with the Commission for approval.[238] Illinois Commission states that it is concerned by the lack of Commission review, given that Midwest ISO's transmission expansion plan imposes enormous costs on electricity customers in the Midwest ISO footprint which will likely increase dramatically if the MVP filing is approved.[239]

188. IPL states that the Commission should require Midwest ISO to add a requirement, similar to provisions in SPP's cost allocation proposal, to protect against disproportionate impacts or unintended consequences.[240] Specifically, IPL states that Midwest ISO should include certain provisions that SPP included in its cost allocation methodology to: 1) require review of its cost allocation methodology and allocation factors at least every three years; 2) authorize the Regional State Committee to recommend any adjustments to the cost allocation if a review shows an imbalanced cost allocation to one or more zones and require that the analytical methods used in the review be defined; and 3) enable member companies that believe they have been allocated an imbalanced portion of costs to seek relief from the Markets Operating and Policy Committee. IPL states that in approving these changes and certain clarifications to SPP's cost allocation provisions, the Commission specifically noted that SPP's "unintended consequences provisions provide a reasonable mechanism for adversely affected parties to raise their concerns through the stakeholder process and for unintended outcomes to be amended."[241] IPL states that the Commission has similarly required Midwest ISO to review and report on how past cost

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[238] *Id.* at 42 (citing Amended and Restated Operating Agreement of PJM Interconnection, LLC, Schedule 6, section 1.6, Substitute Fifth Revised Sheet No. 186). Illinois Commission states that PJM's expansion plan filings have provided a useful forum for interested stakeholders to raise particular issues and concerns with particular projects and particular cost allocations. For example, Illinois Commission states that errors in PJM's cost allocations have been discovered through these filings and the Commission forum provided an opportunity whereby these errors could be adjudicated by the Commission and efficiently corrected by the RTO, thereby obviating the need for litigation.

[239] *Id.* at 40.

[240] IPL Comments at 30.

[241] *Id.* (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 45-48; *see also Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042, at P 95 (2010) (finding SPP's revised unintended consequences provisions to be just and reasonable)).

allocation methods are functioning to determine whether future changes would be necessary.[242]

189. Filing Parties state that Midwest ISO is willing to submit annual reports summarizing the results of the implementation of the proposed Tariff revisions. Filing Parties argue that if a high level of detail will be required, the progress reports should be spread out over a broader time period, such as the 3-year period used by SPP.[243] Filing Parties remind parties that Attachment FF already provides that: "The Transmission Provider shall provide a copy of the MTEP to all applicable federal and state regulatory authorities."[244] Filing Parties also state that Attachment FF provides, in pertinent part, that: "The Transmission Provider shall publish annually, and distribute to all Members and all appropriate state regulatory authorities, a five-to-ten year planning report of forecasted transmission requirements. Annual reports and planning reports shall be available to the general public upon request."[245]

5. Commission Determination

190. Changing operational circumstances in the Midwest ISO region, including continually evolving demands placed on the transmission grid, and corresponding changes to its operation, have prompted a transition from relatively localized transmission system planning to regional planning. Regional planning also addresses new federal and state policy initiatives, such as the increasing adoption of renewable portfolio standards,[246] other state policies that promote increased reliance on renewable energy resources, and a focus by Congress and the Commission on promoting reliability and economically efficient transmission infrastructure development.[247] Collectively,

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[242] *Id.* at 30-31.

[243] Filing Parties October 18, 2010 Answer at 89.

[244] *Id.* (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, Sheet No. 3484).

[245] *Id.* at 89, n.273 (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, Sheet No. 3486).

[246] Some 30 states, plus the District of Columbia, have adopted renewable portfolio standards. Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 30.

[247] *See generally* 16 U.S.C. §§ 824o, 824s (2006) (regarding the siting of interstate transmission facilities and transmission infrastructure investment, respectively); Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 19-22.

these changes result in a growing need for new transmission and appropriate cost allocation for such transmission.

191. 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 not unduly discriminatory basis, the Commission directed each transmission provider to develop a transmission planning process that satisfies nine principles. In adopting "Cost Allocation for New Projects" as one of the nine transmission planning principles, the Commission recognized that knowing how the costs of new transmission facilities would be allocated is critical to the development of new infrastructure, because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.[248] The Commission did not impose a particular cost allocation method, but provided an overall policy framework 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 explained that up-front identification of how the cost of a facility will be allocated will allow transmission providers, customers, and potential investors to decide, on an informed basis, whether or not to build that facility.[249] As noted above, the Commission recently determined in a series of orders that Midwest ISO's transmission planning process complies with the policy framework of Order No. 890.

192. The Commission continues to seek improvements to cost allocation for new transmission projects. The recent Transmission NOPR proposed, among other things, to establish a closer link between transmission planning processes and cost allocation, and to require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.[250] While compliance

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[248] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

[249] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 251. The Commission also stated that neither adoption of a cost allocation method nor identification of an upgrade (whether driven by reliability or economics) in a transmission plan triggers an obligation to build. *Id*.

[250] Specifically: 1) the cost allocation for new (regional or interregional) transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; 2) those that receive no benefit from (regional or interregional) transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities; 3) if a benefit-to-cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional

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with the Transmission NOPR is not at issue here – the Transmission NOPR is a regulatory proposal that was subject to a notice-and-comment procedure under the Administrative Procedure Act, and that has not been finalized – the Commission remains mindful of its goals in evaluating Filing Parties' proposal.

193. Filing Parties' proposal presents the Commission with 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. Evaluation of MVPs will become a component of the Midwest ISO transmission planning process that the Commission has already approved. Like SPP's highway/byway cost allocation, the proposal fits within the Commission's transmission planning policy framework, but it is "adjunct to a regional transmission planning approach,"[251] and is designed to meet specific regional needs.[252]

194. We find that the proposal provides a package of transmission planning revisions that is just and reasonable, and we will accept Filing Parties' proposal. We expect the

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transmission plan for the purpose of cost allocation (or to qualify for interregional cost allocation), it must not be so high that facilities with significant positive net benefits are excluded from cost allocation; 4) The allocation method for the cost of an intraregional (or interregional) facility must allocate costs solely within that transmission planning region unless another entity outside that region or another transmission planning region voluntarily agrees to assume a portion of those costs; 5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a (regional or interregional) transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility; and 6) a transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan (or interregional facilities), such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 164, 174.

[251] SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 22.

[252] *Id.* P 21-22 ("SPP states that a region-wide approach focuses on the development of a robust transmission system that is required to take into account not only reliability issues, but economic opportunities to reduce congestion, as well as state and federal policy goals such as increased use of renewable energy resources, greater incorporation of demand response and energy efficiency technologies, and reduced carbon dioxide emissions.").

functional approach to MVP selection to allow Midwest ISO and its members to achieve a number of goals at one time. First, it allows Midwest ISO and stakeholders to identify transmission projects that will have positive benefits for the grid, and that may also satisfy legal and public policy goals in addition to providing just and reasonable pricing on a non-discriminatory basis. Second, the four-part process provides for thorough, transparent consideration of which transmission projects should receive regional cost allocation. Third, the process allows Midwest ISO flexibility to 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. Finally, we find that the integrated process takes another step toward achieving the goal of facilitating efficient regional transmission planning.

195. 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. According to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[253] The Seventh Circuit recently elaborated on that principle, stating:

> All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To 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.[254]

The cost causation principle thus 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.[255]

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

[254] *Illinois Commerce Commission*, 576 F.3d at 476 (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) (*Transmission Access Policy Study Group*); *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); *Midwest ISO Transmission Owners*, 373 F.3d at 1368; *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Sithe*, 285 F.3d at 4-5).

[255] *Id.* at 476-77 (citing *Midwest ISO Transmission Owners*, 373 F.3d at 1369; *Sithe*, 285 F.3d at 5). The Seventh Circuit further stated: "For that matter, [the

(continued…)

196. The Commission has recognized in earlier cost allocation orders the integration and interdependence of the utilities in Midwest ISO's integrated grid. For example, the Commission has permitted Midwest ISO to apply administrative charges, and charges associated with operating its energy markets, to transactions under grandfathered transmission service agreements that otherwise do not participate in the Midwest ISO energy markets.[256] The Commission found – and the D.C. Circuit agreed – that "all users of the grid operated by the Midwest ISO will benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability of the transmission system."[257] It is therefore appropriate for all users of the grid to share in the costs of programs and activities that benefit the grid as a whole.

197. A fair assessment of costs requires not only identification of entities to which costs should be allocated, but also consideration of those entities that benefit as a result of those costs. We review proposed assessments with the Supreme Court's admonition in mind that "[a]llocation 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."[258] As the Seventh Circuit recently clarified, the Commission "does not have to calculate benefits to the last penny, or for

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Commission] can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. But it cannot use the presumption to avoid the duty of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'" *Id*. at 477 (citing *Western Massachusetts*, 165 F.3d at 927; *Midwest ISO Transmission Owners*, 373 F.3d at 1368).

[256] *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,033 (2001) (applying charges for scheduling, system control and dispatch under Schedule 1 of the Tariff, and for Midwest ISO administrative costs under Schedule 10 of the Tariff), *reh'g denied*, 98 FERC ¶ 61,141 (2002), *aff'd sub nom. Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 (2004) (applying charges for administrative costs associated with energy markets under Schedule 17 of the Tariff), *order on reh'g*, 111 FERC ¶ 61,042 (2005), *aff'd sub nom. Wisconsin Public Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007).

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

[258] Filing Parties July 15, 2010 Filing, Transmittal Letter at 13 (citing *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589, *reh'g denied*, 325 U.S. 891 (1945) (*Colorado Interstate Gas*)).

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that matter to the last million or ten million or perhaps hundred million dollars;" it merely must demonstrate that "it has an articulable and plausible reason" to believe that the benefits are at least roughly commensurate with costs.[259]

198. The Commission has previously recognized circumstances that warranted changes in the manner by which public utilities recover transmission costs. In the early 1990s, the Commission identified "dramatic changes which the electric industry has faced, and will face in the near term," such as "increased reliance on market forces to meet power supply needs; new market entrants such as exempt wholesale generators; a significant number of utility mergers and combinations; more highly integrated operation of various power pools; and substantial bulk power trading among electric systems," as well as the initial filing of open access transmission tariffs.[260] To account for those developments and the industry's changing needs, the Commission issued a policy statement that increased flexibility with respect to transmission pricing.[261]

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[259] *Illinois Commerce Commission*, 576 F.3d at 477. The court went on to say that the Commission:

> is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members…. 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 new 500 kV lines in the East … but it 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; the Commission can approve PJM's proposed pricing scheme on that basis.

Id.

[260] *See Notice of Technical Conference and Request for Comments in Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act*, 58 Fed. Reg. 36,400, 36,401 (1993).

[261] *Policy Statement in Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act*, 69 FERC ¶ 61,086 (1994).

199. In Order No. 890, the Commission stated that, when considering a dispute over cost allocation, it would exercise its judgment by weighing several factors. First, the Commission stated that it would consider 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. Second, the Commission stated that it would consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, the Commission stated that it would consider whether the proposal is generally supported by state authorities and participants across the region.[262] Therefore, the Commission considers first whether Midwest ISO's MVP Methodology fairly assigns costs among Midwest ISO members.

200. We find that the Filing Parties have demonstrated that the MVP proposal is a framework that will result in the allocation of the costs of transmission projects on a basis that is "roughly commensurate" with the benefits of those projects and that the proposal is otherwise just and reasonable. We find that each of the four principal aspects of the proposal is persuasive as we reach this conclusion.

201. First, as further described below, each project must meet one of the three criteria for inclusion as an MVP. This initial screen will ensure that each project can benefit the Midwest ISO region.

202. Second, the portfolio approach to selection of MVPs for cost allocation helps to ensure that the benefits, as well as the costs, of the projects are spread broadly through the Midwest ISO region. The Commission recognizes that it can be difficult, and controversial, to identify which types of benefits are relevant for cost allocation purposes, which entities are receiving those benefits, and the relative benefits that accrue to various beneficiaries in an integrated transmission grid. Experts recognize that "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."[263] The system is planned to maintain reliability with the loss of large transmission lines or the unplanned outages of generation resources. However, the ability of the system to operate reliably under these conditions cannot necessarily be quantified in dollars in the same manner as economic benefits. The inability of a model to economically quantify the reliability benefit of any particular transmission line does

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[262] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

[263] Filing Parties July 15, 2008 Filing, Curran Test. at 27.

not mean that there is no value to reliability. Studies show that customers value dependable electricity and that outages cause real economic losses.[264]

203. Third, the MTEP stakeholder process will provide a venue for the cost-benefit calculation of individual projects. Stakeholders will have an opportunity in the MTEP to review and to challenge studies that quantify the costs and benefits of each individual MVP, and therefore of the regional cost allocation. If there is a lack of unity as to these benefits and costs, the dispute resolution procedures of the Tariff will be available to stakeholders. Stakeholders may also seek alternative dispute resolution through the Commission, or file a section 206 complaint, if the stakeholder process does not satisfy their concerns.

204. Finally, we note that the MVP proposal is generally supported by state authorities and participants across the Midwest ISO region. The stakeholder process for the MVP proposal was both long in duration and inclusive of interested parties. As noted by the OMS, a majority of its members have generally agreed to support its comments supporting the proposal.[265] Additionally, we note that the MVP proposal was approved by the Advisory Committee, which is comprised of nine stakeholder sectors.

205. The Filing Parties' proposal will require "judgment on a myriad of facts," through these various processes, which will be open to Midwest ISO stakeholders, regulators, and other interested parties. We agree that individual review of proposed MVPs, combined with the portfolio approach to selecting projects, allows Midwest ISO to maximize the regional benefits attainable from any year's MTEP, and to ensure that those regional benefits are broadly spread across its footprint.

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[264] *E.g.*, Peter Fox-Penner, *A Year Later, Lessons From the Blackout*, N.Y. Times, Aug. 15, 2004 at 14WC. *See also* Primen, *The Cost of Power Disturbances to Industrial & Digital Economy Companies* (June 29, 2001), at D-1, *available at* http://www.on-power.com/pdf/EPRICostOfPowerProblems.pdf (visited Dec. 14, 2010).

[265] OMS Comments at 14. The members that generally support the MVP proposal are Indiana Commission, Iowa Board, Michigan Commission, Minnesota Commission, Missouri Commission, Montana Commission, North Dakota Commission, South Dakota Commission, and Wisconsin Commission. Illinois Commission, Public Utilities Commission of Ohio, and Pennsylvania Public Utility Commission abstained from the vote on these comments. Manitoba Public Utilities Board did not participate in OMS' pleading. Only Kentucky Public Service Commission explicitly does not support OMS' comments regarding the MVP proposal.

206. Having found the MVP proposal just and reasonable, we need not address the merits of an alternative proposal to allocate costs to generator interconnection customers, as discussed below.[266] However, we agree with parties that the Filing Parties should file annual reports to the Commission, as described below.

a. Criteria

207. As described above, in order to qualify as an MVP, a candidate project must meet at least one of three criteria. Any project that is approved as an MVP must be shown to bring about an increase in reliability or economic efficiency, and Midwest ISO expects that a substantial number of projects approved as MVPs will present multiple types of regional benefits.[267] Under Criterion 1, an MVP must support a qualifying policy initiative 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."[268] Criterion 2 requires that an MVP provide multiple types of economic benefits across multiple pricing zones, and Criterion 3 requires that an MVP address 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. Midwest ISO and stakeholders will review each candidate MVP on an individual basis in order to assess its benefits.

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[266] *See Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (finding that, under the FPA, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology, or even the most accurate one"); *cf. City of Bethany v. FERC*, 727 F.2d 1131, 1136, 234 U.S. App. D.C. 32 (D.C. Cir. 1984) (when determining whether a proposed rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). *See also Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282, at P 31 (2009) (finding that, because the Commission found the ISO's proposal to be just and reasonable, it need not assess the justness and reasonableness of an alternative proposal); *Louisville Gas & Electric Co.*, 114 FERC ¶ 61,282, at P 29 (2006) (March 17, 2006 Order) (finding that "the just and reasonable standard under the FPA is not so rigid as to limit rates to a 'best rate' or 'most efficient rate' standard. Rather, a range of alternative approaches often may be just and reasonable").

[267] Filing Parties July 15, 2010 Filing, Curran Test. at 7.

[268] *Id.* at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet Nos. 3451A-B.

208. We find that Criterion 1 will ensure regional benefits by more efficiently integrating new generation resources to meet documented energy policy mandates or laws throughout the region. Criterion 1 contains a two-prong requirement: An MVP must support documented energy policy goals, as noted above, and it "must be shown to enable the transmission system to delivery such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade."[269] Pursuant to this criterion, any candidate MVP must be subject to an open, transparent analysis in the MTEP of the costs and regional benefits that it will provide, even if the MVP is proposed primarily for reasons of public policy.

209. In response to commenters' concerns about the specific requirements of Criterion 1, we find that it is neither too broad nor too vague. We are sensitive to Filing Parties' need to ensure that transmission expansion projects undertaken to satisfy a diverse array of documented energy policy mandates or laws or regulatory requirements from various jurisdictions are included under Criterion 1. In response to parties' request that the Commission clarify what constitutes compliance with documented energy policy mandates or laws or regulatory requirements, we find that the question should be addressed by Midwest ISO and its stakeholders, which include those jurisdictions. Thus, we reject requests that Criterion 1 be further clarified.

210. Parties who claim that Criterion 1 is overly broad so as to result in overbuilding or inefficient building do not explain how Midwest ISO's open and transparent planning process would fail to give voice to a party or parties who expressed such concerns about a transmission project that is believed not to merit MVP designation. We find that Filing Parties have presented persuasive evidence that MVPs qualifying under Criterion 1 will be driven by substantial need for transmission upgrades.[270] The MVP methodology will support the development of new transmission facilities that among other things will support documented energy policy mandates or laws that presently exist in 11 out of 13 states because the MVP proposal resolves a key issue that is preventing significant new transmission from being built – who pays.

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[269] Filing Parties October 18, 2010 Answer at 15.

[270] *See, e.g.*, Midwest ISO, *Regional Generation Outlet Study* (Dec. 2009), *available at* http://www.midwestiso.org/publish/Document/75871b_126e10582e3_-7c490a48324a/RGOS_I_Executive_Summary_Report_FINAL.pdf?action=download&_property=Attachment. Witness Moeller explains that the Regional Generation Outlet Study is an example of a transmission study that takes a longer-range regional view to develop longer-term solutions that can begin to be implemented in the present. Filing Parties July 15, 2010 Filing, Moeller Test. at 10.

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211. AMP voices concern that Criterion 1 is silent on application to municipal laws and that, were a municipality's mandates to be excluded, imposing MVP costs on that municipality's load would be unduly discriminatory. We are not clear if this is a present concern, that is, if AMP or another municipal entity has developed a mandate that is apart from the mandate of its state. We believe that this issue should be addressed in Midwest ISO's stakeholder process.

212. Finally, we disagree with PSEG Companies' assertion that Filing Parties' are attempting to make determinations regarding how states or load-serving entities should meet federal or state public policy requirements. PSEG Companies appear to suggest that Midwest ISO and the other Filing Parties will be putting themselves in the position of state commissions. However, we expect that state regulators and other stakeholders will be actively involved in identification of MVPs, and that, as a transmission provider, Midwest ISO will be receiving input from, and acting in conjunction with, the state commissions. We recognize the importance of involving state commissions, as well as regional state committees such as OMS, and all other stakeholders, in making decisions about projects being developed and built in the Midwest ISO region and elsewhere. This is particularly so in light of the diversity among the Midwest ISO sub-regions and its market participants. We are confident that Midwest ISO's existing transmission planning process, which Midwest ISO and its stakeholders developed as part of the Order No. 890 compliance process, will continue to allow all stakeholders, including state regulators, to participate in the development and identification of transmission projects, including candidates for MVP cost allocation.[271]

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[271] May 2008 Planning Order, 123 FERC ¶ 61,164. Section I.A.2 of Attachment FF of the Midwest ISO Tariff includes procedures for stakeholder input into the planning process. Stakeholder participation is currently accomplished through the Planning Advisory Committee, which is responsible for addressing planning policy issues of importance to stakeholders. The Planning Advisory Committee reports to Midwest ISO's Advisory Committee. We also remind commenters that section I.A.14 of Attachment FF provides dispute resolution procedures that specifically address how Midwest ISO will handle disputes that arise in the development of an MTEP or the cost allocation associated with projects.

Given the above-procedures for stakeholder input, we disagree with Illinois Commission that the out-of-cycle review process allows transmission owners to get project approval by circumventing the MTEP process and stakeholder review. The out-of-cycle review process is still subject to all other requirements contained within Attachment FF (e.g., openness, transparency, and information sharing).

213. We find that Criterion 2 appropriately ensures that the projects that qualify for MVP status under its conditions generally will have broad regional benefits such that applying regional cost sharing is just and reasonable. From its definition, projects that qualify for MVP status under Criteria 2 must demonstrate multiple types of economic benefits in multiple pricing zones and that the benefits of such projects exceed the associated costs of such projects. As such, Criterion 2 ensures that the projects qualifying for MVP status have regional benefits, and protects against projects with only localized benefits qualifying from receiving broad regionally cost sharing. We also note that Criterion 2 provides a rigorous qualification standard because not only do the economic benefits have to be demonstrated to be widespread, but to qualify for MVP status a project would need to have multiple types of economic benefits. A project demonstrating only production cost savings in multiple zones would not be sufficient, but the project would have to additionally demonstrate other economic benefits such as capacity losses savings or reductions in the overall planning reserve margins in order to qualify for regional cost sharing.

214. As to those parties that argue that Market Efficiency Projects are subject to a different benefit-to-cost ratio test than MVPs, we find that the arguments made are not relevant here. In this proceeding, the Commission is only making a determination as to whether the 1.0 benefit-to-cost ratio for MVPs under Criterion 2 is just and reasonable. While we note that commenters have submitted anecdotal evidence to further their argument that the benefit-to-cost ratio test for Market Efficiency Projects may be too stringent, we also note that Midwest ISO has committed to a new RECB stakeholder process to evaluate other cost allocation issues in the near future. Filing Parties state that the benefit-to-cost ratio for Market Efficiency Projects would be part of that stakeholder process.[272] In any case, because MVPs are projects that provide regional benefits, we find that a benefit-to-cost ratio of 1.0 is just and reasonable because it ensures that the multiple economic benefits to all users is at least equal to the costs allocated to all users over the 20 years of service that are evaluated. Moreover, we also agree with Filing Parties that benefits are expected to accrue well after 20 years of service.[273]

215. We find that Criterion 3 will ensure that the projects that qualify for MVP status under its conditions generally will have broad regional benefits such that applying regional cost sharing is just and reasonable. Criterion 3 requires that qualifying projects address at least one transmission issue associated with a projected violation of a NERC or Regional Entity Reliability Standard and at least one economic based transmission issue

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[272] Filing Parties July 15, 2010 Filing, Curran Test. at 16-17.

[273] We will address concerns that Criteria 2 and 3 subsume RECB categories of network upgrades in a separate section of this order.

that provides economic value across multiple pricing zones. Criterion 3 also will ensure the total financially quantifiable benefits are in excess of the total project costs. Similar to projects qualifying for MVP status under Criterion 2, projects that qualify under Criterion 3 generally would be providing widespread regional benefits. Applying Criterion 3 protects against Midwest ISO granting regional cost sharing to projects that solve reliability issues but only provide local economic benefits. Criterion 3 applies a tough standard to ensure qualifying projects are in fact regionally beneficial as such projects have to show that they are both beneficial to the region in addressing a projected reliability violation and in providing regional economic benefits. We also note that the cost threshold for the MVP is $20 million which will help ensure that that projects qualifying for MVP status under Criterion 3 are regional in nature. As such, we believe Criterion 3 applies appropriate and rigorous standards to ensure MVPs that have more than one purpose (i.e. they provide both economic and reliability value) also have regional benefits such that regional cost sharing is appropriate. We reject ATC's request for clarification that a project being considered under Criterion 3 should only have its benefits compared to the costs of the "economic" portion of the project. Granting the clarification ATC seeks would subvert the premise that total benefits must be greater than the total costs for a project to receive regional cost sharing and would have the effect of lowering the *de facto* benefit-to-cost ratio test to something less than 1:1.

216. In sum, the provisions of Criteria 1, 2, and 3 persuade us that each candidate MVP will provide the Midwest ISO region with an identifiable regional benefit, and in many cases multiple such benefits. We therefore reject, as unnecessary, suggestions to modify the proposal to remove any of the criteria or to require that MVPs qualify for cost-sharing by meeting more than one of the criteria. We find that the criteria, read individually and together, require Midwest ISO to analyze each candidate MVP in MTEP to evaluate its individual costs and benefits.

217. We also accept Filing Parties' proposal to allow projects rated at 100 kV or higher (including any lower-voltage underbuild) to receive regional cost sharing under the MVP methodology. In the RECB II proceedings, the Commission accepted the 345 kV voltage threshold for projects to receive 20-percent regional cost sharing because Midwest ISO demonstrated that for a utility to "self-serve" its load reliably, such service would have a 20-percent reliance on the overall transmission systems. That is, even though these projects were generally intended for local generation to serve local load, there was still a 20-percent to 30-percent regional usage component.[274] Here, even though we are not accepting a bright-line 345 kV voltage threshold for a project to qualify for MVP cost allocation, the 100 kV voltage criterion that we are accepting, together with the three

[274] *See* RECB II Order, 118 FERC ¶ 61,209 at P 47.

functional criteria and the $20 million minimum project cost requirement associated with MVP facilities, lends assurance that the facility's benefits will be of sufficient size and scope to be material to the Midwest ISO region as a whole.

218. In particular, we agree with Filing Parties that the "backbone" transmission system of the Midwest ISO footprint varies and, in some areas, the backbone is 161 kV. Thus, a change of the voltage threshold from 100 kV to 230 kV or above would undermine any regional development in those areas and could produce unduly discriminatory results. Further, as Filing Parties point out, the 100 kV threshold represents the minimum size transmission facility over which Midwest ISO generally exercises functional control.

219. For those parties protesting the 100 kV voltage threshold by generally stating that 100 kV facilities perform a more local function, such an argument ignores the specific criteria established by Filing Parties. Filing Parties' proposal requires that qualifying facilities provide regional benefits as described by one of three MVP criteria. The voltage cutoff in the MVP proposal serves to ensure the materiality of the project; however, it does not qualify the project. A project that meets the voltage cutoff must still be evaluated on the basis of whether it meets the criteria proposed by Filing Parties. Therefore, we do not accept the suggestion that we create a rebuttable presumption that network upgrades required for generator interconnection rated at 345 kV or higher automatically qualify as MVP.

220. As to the suggestion that an underbuild facility should not receive MVP treatment, we find that the costs of underbuilds that are not required but for the MVP (i.e., that are required solely to address reliability impacts of an MVP) should not be assigned solely to the local load as such a result is counter to cost causation principles, as the MVP would cause the need for these improvements.[275] We find that it is appropriate to allocate the costs of the underbuild associated with a MVP because it is these underbuild facilities that will ensure reliable system operation in case of an outage of the MVP facility. For example, if a MVP transmission line trips off-line due to a fault, it is the remaining transmission system and the underbuild associated with that MVP transmission line that will prevent a cascading failure of the transmission system.

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[275] We will also reject MPPA's request to limit underbuild costs to 50 percent of the combined project cost. We find that it is just and reasonable to assign the costs of underbuild facilities to the same entities that benefit from the associated higher voltage facilities. We also disagree with the suggestion that the definition of underbuild unreasonably includes upgrades determined by Midwest ISO's contingency analysis to existing resources. We find that it is appropriate for Midwest ISO to plan its system to accommodate both existing and planned resources, and allocate costs accordingly.

b. Portfolio Approach

221. According to Filing Parties, projects designated as MVPs will "be reviewed holistically on a 'portfolio' basis, taking into account the synergistic effects of individual qualifying MVPs, and approving the set of MVPs that collectively comprise an optimized regional solution."[276] Filing Parties go on to explain that:

> MVPs are multi-faceted projects that collectively comprise an optimal regional solution. Those commenters who are focused on one specific project overlook the collective regional benefits of multiple MVPs that are evaluated as a portfolio or package. This package of projects is designed (and evaluated) to provide a regional solution that globally benefits all users of the Midwest ISO transmission system. It is illogical to isolate one facet of this packaged solution.[277]

As described, the portfolio approach will help Midwest ISO to prioritize its transmission expansion projects in such a way as to ensure global benefits from the projects afforded regional cost sharing and maximize the number of system users who will share in those benefits. Midwest ISO's ability to move projects in a portfolio forward with an eye to the benefits for the entire region will also assure that its analysis takes into proper consideration the need to match costs with benefits.As the Commission stated with regard to SPP, "[w]e recognize that every utility will have different transmission needs depending on its unique load profile and resource mix. However . . . we find that the SPP zones are similarly situated in the context of transmission planning and cost allocation because all of the zones consist of RTO participants, users, and beneficiaries of the same regionally-integrated [extra-high voltage] transmission network. As such, they accrue certain benefits common across all SPP zones."[278] We find that this applies to the Midwest ISO region as well.

222. We find that the portfolio approach resolves the concerns of the protestors who propose disparate treatment for certain portions of Midwest ISO. Protestors' arguments do not acknowledge the integrated nature of the system or the potential for upgrades in one area to improve the entire system. The D.C. Circuit has found that the integrated nature of the grid justifies spreading costs broadly:

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[276] Filing Parties October 18, 2010 Answer at 15.

[277] *Id.*

[278] SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 82.

> [E]ven if they are not in some sense *using* the ISO, the MISO Owners still benefit from *having* an ISO. In this sense, [Midwest ISO] is somewhat like the federal court system. It costs a considerable amount to set up and maintain a court system, and these costs – the costs of *having* a court system – are borne by the taxpayers, even though the vast majority of them will have no contact with that system (will not *use* that system) in a given year. . . . The MISO Owners' position is tantamount to saying that if they are not a litigant, they should not be made to pay for any of the costs of *having* a court system. Since the MISO Owners do, in fact, draw benefits from being part of the [Midwest ISO] regional transmission system, [the Commission] correctly determined that they should share the cost of *having* an ISO.[279]

We note that we are accepting a functional method of determining which projects should qualify as MVPs, and we are not determining whether any projects meet those qualifications. Some protestors point specifically to the Michigan Thumb Project as an MVP candidate that will not provide regional benefits.[280] Both load inside of and outside of Michigan will receive, and continue to receive, broad regional benefits from the integrated Midwest ISO transmission system and the broader Midwest ISO/PJM bulk power system and its regional pricing structure. We are not convinced by certain protestors' claims that they expect to shoulder an unfair amount of the costs associated with MVPs based on the costs of a single specific project, such as the Michigan Thumb Project. Furthermore, we note that the Commission eliminated through-and-out rates between Midwest ISO and PJM in part to address connectivity issues and that this order maintains the elimination of those through-and-out rates. The change in the utilities' RTO memberships will not affect the physical connections between their systems or the rates paid to transmit across them.

223. We are concerned, however, that Midwest ISO has not stated its portfolio approach in the Tariff. We therefore require Midwest ISO to submit, within 60 days of the date of this order, a compliance filing to revise the Tariff to state that MVPs will be reviewed on a portfolio basis.

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[279] *Midwest ISO Transmission Owners*, 373 F.3d at 1371.

[280] ABATE points to the physical interconnections between utilities in Michigan and the rest of Midwest ISO to show that, once FirstEnergy leaves Midwest ISO and joins PJM in 2011, the only remaining interconnections between Michigan and Midwest ISO will be two 138 kV lines in the Upper Peninsula of Michigan and one 138 kV between METC and NIPSCO.

c. Stakeholder Process

224. The Commission requires RTOs and ISOs to maintain a coordinated, open and transparent transmission planning process on both a regional and a local level.[281] Transmission-owning members of the RTO or ISO must participate, and "[i]n order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process."[282] The Midwest ISO's transmission planning process, as we have noted above, already has been found to be consistent with Order No. 890; the proposal here will merely add another dimension to the planning process.

225. Midwest ISO makes clear that the process of identifying MVPs will be open and transparent, in accordance with Order No. 890:

> The Commission-approved planning process offers multiple opportunities for all stakeholders, from transmission owners to state regulators to generators, to provide input and feedback on all aspects of a study from assumptions to results. MVPs will move through the same Commission approved planning process. Furthermore, it is anticipated that scrutiny by stakeholders will be increased given the regional size, scope, and cost sharing of MVPs. . . . Monthly stakeholder meetings are planned for the duration of the study to communicate the results of detailed engineering and economic analyses, and obtain feedback from stakeholders, as appropriate.[283]

226. Based on Filing Parties representations, we find that the stakeholder process will permit stakeholders to provide their input on the designation of projects as MVPs, including the projects' costs, benefits, and compliance with the inclusion criteria. We note again that if there is a lack of unity as to these benefits and costs, the dispute resolution procedures of the Tariff will be available to stakeholders. Stakeholders may also seek alternative dispute resolution through the Commission, or file a section 206 complaint, if the stakeholder process does not satisfy their concerns.

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[281] Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 435.

[282] *Id.* P 440.

[283] Filing Parties October 18, 2010 Answer at 35.

d. Studies

227. Cost allocation, as we have explained above, requires "judgment on a myriad of facts,"[284] and the Commission must have "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with the costs in question.[285] The studies that Midwest ISO uses to analyze candidate MVPs will provide such a basis for cost allocation.

228. As described above, the MVP proposal is intended to bring to the Midwest ISO region projects that will have regional benefits. To support this proposition, Filing Parties submit a list of MVP starter projects, and states that it expects those projects to win approval for regional cost sharing in MTEP. Its witnesses describe an array of benefits from these projects.

229. We find that Filing Parties have submitted persuasive evidence that supports a broad approach to cost allocation for projects that qualify as MVPs. Filing Parties performed an analysis of the MVP starter projects and estimate that these projects will deliver between $582 million and $798 million in annual economic benefits starting in 2015 from expected production cost savings, reductions in transmission losses, and a reduction in the region's reserve margins.[286] Filing Parties divide these estimated annual savings into the following categories:

- Between $297 million and $423 million in annual adjusted production cost savings, spread almost evenly across all Midwest ISO Planning Regions;
- Between $68 million and $104 million in annual transmission system loss savings when the starter projects are put into service;[287] and
- Between $217 million and $271 million in annual reductions of the region's reserve margin is realized due to load diversity.[288]

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[284] *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589, *reh'g denied*, 325 U.S. 891 (1945).

[285] *Illinois Commerce Commission*, 576 F.3d at 477.

[286] Filing Parties July 15, 2010 Filing, Curran Test. at 26.

[287] This estimate is associated with an annual reduction in transmission losses of approximately 1,500,000 to 2,000,000 MWh. *Id.*, Curran Test. at 24.

230. Filing Parties note that higher production cost savings and savings in deferred capacity investment could add billions of dollars to this indicative estimate of the MVP starter projects in the long run.[289] For example, Filing Parties estimate that the annual production cost savings, listed in the first bullet above, increases to between $400 million to $1.3 billion by 2025.

231. Filing Parties state that related benefits quantified from the MVP starter projects include annual potential load cost savings ranging from $14 million to $984 million in 2015 and negative $19 million to $2 billion in 2025.[290]

232. Filing Parties indicate that further benefits may be realized, although these further benefits were not quantified from the MVP starter projects. They state that even a relatively small reduction of 0.5 percent in reserve requirements would result in a deferral of about 500 MW of capacity investment, saving approximately $500 million.[291] Filing Parties also indicate that a transmission system that is more resilient to contingencies, and thus more reliable, should reduce wind facility curtailments by approximately 25 percent in the east region.[292]

233. By contrast, Curran states that the estimated annual revenue requirement for the starter projects is $675 million.[293]

234. Some parties find fault with the studies performed by Filing Parties. The debate centers on the inputs and assumptions used in the various studies. Several protestors raise objections to those inputs. However, we find that Filing Parties have provided persuasive evidence that their choice of inputs, although questioned by protestors, is reasonable. Filing Parties explain that peak load forecasts used in the transmission studies were provided by load-serving entities for use in resources adequacy studies. These estimates were not calculated by Filing Parties. Filing Parties also defend their estimate of the cost of new entry, stating that it is roughly between the cost of a new combustion turbine and combined cycle unit. Further, they state that the estimate is

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[288] *Id.*, Curran Test. at 26.

[289] *Id.*

[290] *Id.*, Lawhorn Test. at 13-14.

[291] *Id.*, Curran Test. at 25.

[292] *Id.*, Transmittal Letter at 16-17, Lawhorn Test. at 12-14.

[293] *Id.*, Curran Test. at 26.

conservative, given that the current interconnection queue includes coal and nuclear units with much higher costs of entry.[294] Indeed, Iowa Advocate makes an argument so broad that would call into question the ability to make forecasts. As to Iowa Advocate's specific argument that there is no guarantee that states in the eastern portion of Midwest ISO will buy renewable power from the western portion, we note that 11 of the 13 Midwest ISO states themselves have renewable portfolio standards of one sort or another. Thus, it is reasonable to conclude that there will be purchases of renewable energy by many states from sources in other areas of Midwest ISO, including from west to east.

235. MICH-CARE states that it is likely that residential customers who live far away from an MVP would receive little or no benefit, yet they would be required to help pay for the project under the Midwest ISO proposal. As MICH-CARE explains, this is especially acute for Michigan because of the state's relative isolation from the bulk of the Midwest ISO system.[295] Michigan, MPPA states, will represent approximately 20 percent of the load in Midwest ISO and thus under Midwest ISO's proposal to pay approximately 20 percent of the costs of all MVPs. Since Michigan law requires them to rely on in-state renewable resources, MPPA states, it cannot receive such benefits.[296]

236. However, MICH-CARE's arguments would require acceptance of the notion that load in Michigan does not benefit from bordering Midwest ISO transmission facilities. We disagree. Midwest ISO operates its transmission system and its energy and operating reserves markets on a single-system regional basis to reliably and efficiently integrate resources to serve loads throughout its entire footprint. The strong regionally-integrated transmission network that results from Midwest ISO's independent regional planning provides reliability and efficiency benefits to all that are interconnected to it. The fundamental benefit of the MVP facilities supporting regional power flows is the flexibility they provide to deliver energy and operating reserves more efficiently and reliably within and between balancing areas throughout the Midwest ISO footprint. Although such benefits may accrue at different times to different customers with respect to different groups of transmission projects that enter the plan, these benefits will be widely experienced by Midwest ISO members and will accrue over time. Moreover, by ensuring that MVPs will provide regional benefits through application of the MVP criteria and by assembling these same projects into a portfolio of projects that span

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[294] Filing Parties October 18, 2010 Answer at 22.

[295] MICH-CARE Comments at 5-6.

[296] MPPA Comments at 8.

Midwest ISO, the MVP methodology will ensure that allocations of costs are roughly commensurate with associated benefits.[297]

237. The fact that protestors would have chosen to use different study methods and assumptions than Midwest ISO does not necessarily render Midwest ISO's analysis unreasonable to demonstrate the benefits derived from the MVP starter projects.

238. Filing Parties also performed a transmission usage study (a mileage-weighted analysis) of the MVP starter projects as well as other projects rated at 345 kV and above which demonstrated that the utilization of these transmission facilities would be approximately 80-percent regional. We find that these results regarding transmission usage provide additional evidence to support the regional benefits of MVPs.

e. Alternative Cost Allocation

239. As noted in the October 23, 2009 Order, the Commission has recognized that location-constrained resources present unique challenges that other resources do not present.[298] The July 9 Applicants in the Docket No. ER09-1431-000 proceeding stated that applying the then-existing Line Outage Distribution Factor methodology to allocate costs of generation interconnection network upgrades imposed disproportionate costs on loads in the pricing zones where new generation locates, when the pricing zone in question has high levels of new generation concentration relative to its load. The July 9 Applicants in that proceeding stated that, absent the Commission accepting their proposal, it is virtually certain that Otter Tail Power Company and Montana-Dakota Utilities Company would file to withdraw from Midwest ISO rather than exposing customers in their respective zones to dramatically increased costs.[299] To address these disproportionate effects, the July 9 Applicants proposed to assign between 90 and 100 percent of the costs of network upgrades that would not be required "but for" the generator interconnection customer to the interconnection customer. The Commission's acceptance was conditioned upon the July 9 Applicants fulfilling their commitment to file superseding Tariff revisions regarding the Phase II cost allocation methodology on or

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[297] We find that the concern here relates to cost overruns, and this issue is more appropriately addressed in proceedings seeking to disallow imprudent costs, if such overruns occur as a result of imprudence.

[298] October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58 (citing, *e.g.*, *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,061, *reh'g denied*, 120 FERC ¶ 61,244 (2007)). *See also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 543, 548-549.

[299] Midwest ISO July 9, 2009 Filing, Docket No. ER09-1431-000, Transmittal Letter at 2-3.

before July 15, 2010 as just and reasonable and not unduly discriminatory or preferential.[300]

240. Despite several parties' request that the Commission direct Midwest ISO to assign MVP costs to generators, we believe that the MVP proposal strikes a balance by retaining the existing generator reimbursement policy[301] while allowing a means for generators to mitigate those costs by choosing to site their projects closer to MVP facilities and we will reject the calls for assigning a portion of MVP costs to generators. Parties that suggest that the proposal will lead to inefficient siting miss the point that a major goal of this proposal is to incent generators to locate closer to qualified MVP facilities. Generators that nevertheless site in locations electrically distant from MVP facilities will bear cost responsibility for those interconnection costs.[302] For the reasons discussed herein, we find Filing Parties' proposal not to assign MVP costs to generators to be just and reasonable. Having found the MVP proposal just and reasonable, we need not address the merits of an alternative proposal.[303]

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[300] October 23, 2009 Order, 129 FERC ¶ 61,060 at P 49.

[301] As discussed below, we find that the MVP proposal strikes an appropriate balance between generation developers and other interests in Midwest ISO by retaining the existing reimbursement policy of 90-percent participant funding for network upgrades that would not be required "but for" the generation developer while providing a means for generation developers to mitigate those costs by choosing to site near MVPs.

[302] On Alliant's concerns that this pricing signal does not exist in ATC and ITC – where interconnection customers are fully reimbursed for their facilities – we have previously found that reimbursement policies are only one of various factors that would be considered in siting. The other factors include, for instance, the initial outlay required for network upgrades required for interconnection, the proximity to fuel sources, rights of way, any congestion and/or the time required for the necessary network upgrades to be built permitting delivery of the generation. *See* August 7, 2008 Order, 124 FERC ¶ 61,150 at P 19. In any case, Filing Parties are not proposing to change any reimbursement policies.

[303] *See Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (finding that, under the FPA, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology, or even the most accurate one"); *cf. City of Bethany v. FERC*, 727 F.2d 1131, 1136, 234 U.S. App. D.C. 32 (D.C. Cir. 1984) (when determining whether a proposed rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). *See also Cal. Indep. Sys. Operator Corp.*,

(continued…)

241. In sum, the present proposal not only addresses the challenge of interconnecting location-constrained resources in the western reaches of Midwest ISO, but facilitates investment in qualifying transmission projects throughout Midwest ISO. In addition the proposal addresses multiple reliability and/or economic issues affecting multiple transmission zones

242. We disagree with commenters that Filing Parties' proposal will lead to overinvestment in transmission. The Commission finds that there are sufficient safeguards in place to protect parties against excessive costs. For example, Midwest ISO transmission planning process provides information and opportunity for comment on transmission upgrades and is a transparent process administered by an independent entity charged with ensuring cost-effective planning. Midwest ISO's transmission planning process takes a least-cost approach when selecting the preferred solution, among alternatives, to an identified need. In addition, individual siting decisions and rate approval exercised by the state commissions provide additional protection against excessive costs.

f. Annual Reporting

243. We appreciate commenters' suggestions as to Midwest ISO filing annual informational reports with the Commission regarding the selection of MVPs. Although the recommendations to publish on its website and make annual informational filings with the Commission are reasonable, we agree with Midwest ISO that requiring reports more frequently is unnecessary and time prohibitive. Accordingly, we require Midwest ISO to submit ongoing annual informational reports with the Commission describing the selection of MVP facilities. Midwest ISO should work with its stakeholders to assess the achievements and shortcomings of the MVP selection process after each full planning cycle has been completed and file an informational report with the Commission. We will

not preempt the MTEP process by determining in this docket that any of the starter projects is or is not an MVP.[304]

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128 FERC ¶ 61,282, at P 31 (2009) (finding that, because the Commission found the ISO's proposal to be just and reasonable, it need not assess the justness and reasonableness of an alternative proposal); *Louisville Gas & Electric Co.*, 114 FERC ¶ 61,282, at P 29 (2006) (March 17, 2006 Order) (finding that "the just and reasonable standard under the FPA is not so rigid as to limit rates to a 'best rate' or 'most efficient rate' standard. Rather, a range of alternative approaches often may be just and reasonable").

[304] We cannot grant Iberdrola's request for clarification of the Community Wind

(continued…)

244. With regard to Illinois Commission's suggestion that Midwest ISO file the MTEP report annually, pursuant to section 205(c) of the FPA, we find this requirement unnecessary since Midwest ISO is already required to provide the annual MTEP report to all applicable federal and state regulatory authorities on an annual basis pursuant to its Tariff. We find that this requirement, in addition to the informational filings with the Commission we require above, will provide stakeholders, including state regulators, adequate knowledge of and opportunity to challenge the selection of projects and the associated cost allocation. In addition, we encourage state commissions to be actively involved in the Planning Advisory Committee, Planning Subcommittee and Sub-Regional Planning meetings so that they may actively inform Midwest ISO and its other stakeholders of their concerns and make suggestions for the selection of the MVPs and other projects. Similarly, we find it unnecessary to require Midwest ISO to include an "unintended consequences" provision similar to that which is included in the SPP tariff since the process for determining projects eligible for regional cost sharing is different. Under Filing Parties' proposal, stakeholders will be able to review the selected projects and the associated cost allocation as this information is being disseminated through each of the committees, in addition to the required website postings and informational filings.[305]

B. Other Issues Raised Regarding MVP Criteria

245. In addition to the issues discussed above, numerous parties raise issues regarding other elements of the proposal. For instance, in the RECB I and RECB II cost allocation proceedings, Midwest ISO used $5 million as the minimum project cost threshold for a project to be eligible for 20-percent regional cost sharing. In this proceeding, Filing

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decision in this proceeding; such requests must be filed in the docket in which the original order was issued.

[305] IPL believes that the Commission should consider requiring Midwest ISO to implement cost caps similar to those that the Commission adopted by California Independent Transmission System Operator Corp. (CAISO) to mitigate the cost shift associated with transitioning from utility-specific rates to one CAISO grid-wide rate. IPL Comments at 31-32 (citing Opinion No. 478, 109 FERC ¶ 61,301, June 2, 2005 Rehearing Order, 111 FERC ¶ 61,337). At the outset, we note that the Opinion No. 478 at P 74 addressed a cost cap that did not apply to expansion facilities that were developed in conjunction with and with the approval of the ISO to benefit the entire ISO-controlled grid. Nonetheless, we note that the opportunity for stakeholders to review and comment on proposed MVPs also addresses IPL's suggestion that the Commission consider requiring Midwest ISO to implement cost caps similar to those the Commission approved in Order No. 478.

Parties propose to require MVPs to have a minimum project cost of $20 million in order to be eligible for 100-percent regional cost allocation. Numerous parties provide arguments both for and against the proposal.

246. Another issue raised by parties relates to how the MVP proposal will relate to the cost allocation methodologies in the RECB I and RECB II proceedings. More specifically, certain parties are concerned that the MVP cost allocation methodology will subsume or otherwise render moot the cost allocation methodologies for Baseline Reliability Projects and/or Market Efficiency Projects.

247. Finally, many parties argue that, as proposed, the MVP cost allocation methodology improperly precludes network upgrades that arise from a transmission service request from receiving 100-percent regional cost allocation.

1. Comments

a. $20 Million Cost Threshold

248. Edison Mission argues that Filing Parties have not adequately justified the $20 million cost threshold for projects to qualify for MVP cost allocation. Edison Mission states that the Commission should eliminate the $20 million cost threshold, or in the alternative, reduce it to $5 million consistent with the thresholds established for Baseline Reliability Projects and Market Efficiency Projects.[306] E.ON agrees that the capital cost threshold must be lowered to $5 million. Alternatively, E.ON suggests that the Commission order Filing Parties to provide empirical data demonstrating that a $20 million threshold: 1) will not perpetuate cost barriers to new wind generation development; and 2) will not result in unjust and unreasonable rates.[307]

249. On the other hand, OMS, Iowa Board, NIPSCO and OCC submit that the cost threshold for qualifying for MVP cost allocation should be raised from $20 million to $50 million.[308] OCC argues that the $20 million cost threshold be increased to $50 million in order to be more closely aligned with the known costs of Filing Parties' starter projects. Additionally, OCC states that the Commission should direct Filing Parties to remove the 5 percent of net plant requirement because it may result in

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[306] Edison Mission Comments at 15.

[307] E.ON Comments at 14.

[308] OMS Comments at 11; Iowa Board Comments at 12; NIPSCO Comments at 7; OCC Comments at 9.

insufficiently small projects qualifying for MVP cost allocation without providing sufficient regional benefits to meet documented federal and state energy policy mandates or laws.[309]

b. Arguments that MVP Criteria 2 and 3 Projects will Subsume RECB I and II Projects

250. MICH-CARE opposes the proposal as submitted. MICH-CARE claims that the criteria proposed by Midwest ISO to qualify a project as an MVP "would likely incent many future transmission projects to be classified as MVPs thereby shifting enormous costs across the [Midwest ISO] footprint."[310]

251. Illinois Commission, IPL, Industrial Customers, and NIPSCO argue that MVP Criterion 2 will effectively subsume the Market Efficiency Projects.[311] These parties believe that the latter type of project allocates costs in a more targeted manner which was approved by the Commission.

252. Industrial Customers assert that the $15 million difference in cost threshold between a project that would be subject to a benefit-to-cost ratio of up to 3:1 to receive a 20-percent regional postage-stamp allocation (under RECB II) and a project that would be subject to a benefit-to-cost ratio of 1:1 to receive 100-percent regional postage-stamp allocation is inappropriate. Instead, Industrial Customers argue that it would be simpler and more appropriate for Filing Parties to eliminate Criterion 2 and modify the requirements for a project to qualify as a Market Efficiency Project.

253. Similarly, Illinois Commission, IPL, Industrial Customers, Michigan Commission, and MPPA argue that Criterion 3 would essentially subsume the Baseline Reliability Project category and cost allocation developed in the RECB I proceeding and therefore, should be removed from the MVP proposal.[312] Specifically, Illinois Commission states that the distinct contributions to the need for projects to meet NERC standards are directly quantifiable in terms of power flows and other economic benefits are also quantifiable. Therefore, Illinois Commission claims that allowing Baseline Reliability

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[309] OCC Comments at 9.

[310] MICH-CARE Comments at 8.

[311] *See also* Designated PJM Parties Comments and MISO Northeast Transmission Customers Comments.

[312] *Id.*

Projects and their targeted cost allocation to be absorbed by the MVP category and its postage-stamp cost allocation is unreasonable.

c. Exclusion of Projects Driven Solely by Interconnection Requests or Transmission Service Requests

254. Many parties argue that Filing Parties' proposal should not exclude transmission upgrades associated with generator interconnection requests from receiving MVP cost allocation. Integrys argues that the provisions of proposed section II.C.2.f of Attachment FF (precluding network upgrades driven by generator interconnection or transmission service requests from qualifying as MVP facilities) is inconsistent with Order No. 890 and the Generator Interconnection Procedures in the Midwest ISO Tariff (Attachment X). Integrys argues that to allow this language to stand is contrary to the filed and approved rate doctrine.[313]

255. Similarly, AWEA-WOW request that the Commission require Filing Parties to clarify the MVP criteria in proposed Tariff section II.C.2.f such that it is clear that a transmission line that supports more than one interconnection request required to meet state or federal energy policy can be considered for MVP cost allocation.[314] In this vein, Edison Mission states that the Commission should require Filing Parties to modify the proposal so that "Network Upgrades driven solely by a single Interconnection Request or a single Transmission Service request will not be considered MVPs."[315]

256. Industrial Customers also argue that in cases where a transmission project fails the benefit-cost ratio test and shows no broad-reaching economic benefit, yet is chosen for development due to un-quantified public policy objectives or reliability benefits, the cost of such projects should not be allocated region-wide.[316]

2. Answers

257. In its answer, Filing Parties state that the proposed $20 million threshold is appropriate and provides another mechanism that helps ensure MVPs are limited to projects that are regional in nature without being overly exclusive. Filing Parties state

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[313] Integrys Comments at 10-11. *See also* Acciona Comments at 11.

[314] AWEA-WOW Comments at 32.

[315] Edison Mission Comments at 13.

[316] Industrial Customers Comments at 19.

that of all the Baseline Reliability Projects approved in MTEP06 to MTEP09 or pending approval in MTEP10, only 34 percent have had a total cost exceeding $20 million.[317] Thus, Filing Parties state that the Baseline Reliability Project cost allocation methodology is still pertinent since there are numerous projects that either do not meet the minimum cost threshold for MVP status or do not provide reliability or economic benefits in multiple pricing zones for the first 20 years of the project's life. Filing Parties also state that they would object to lowering the cost threshold to $5 million because that would preclude a primary means of making the distinction between projects that are generally local in nature and those that are regional in nature.

258. As to whether MVP Criterion 2 will subsume or otherwise render Market Efficiency Projects obsolete, Filing Parties state that there are many projects that will not meet either the cost threshold test or the benefits tests that will allow a project to be categorized as an MVP and therefore, the Market Efficiency Project methodology will still be utilized by projects seeking some regional cost sharing. Filing Parties reiterate that in order to qualify for regional cost sharing, an MVP must have a scope and benefits that are more regional than local. To that end, Midwest ISO states that Criterion 2 was drafted to capture projects with multiple benefits or that affect multiple zones, rather than the narrowly tailored RECB II method for Market Efficiency Projects which focus on specific and localized benefits. For example, Filing Parties contend that a transmission project that provides congestion relief in a single pricing zone would not qualify as an MVP because only a production cost savings would be realized and then only in a single zone. Filing Parties continue by stating that even if this production cost savings was realized in more than one zone, it still would not qualify as an MVP because it would only produce one type of economic benefit.

259. Filing Parties state that selecting MVP candidates from upgrades that solely arise from the Generator Interconnection process would defeat the purpose of the MVP which considers other factors. However, Filing Parties note that the MVP proposal does not eliminate the possibility that contingencies identified in a Generator Interconnection Agreement will become MVPs. Filing Parties state that the MVP proposal already accounts for the possibility that upgrades identified for individual projects in the Generator Interconnection process will also be identified (in whole or in part) as MVPs. Specifically, Filling Parties state that a network upgrade that is under consideration for inclusion in MTEP Appendix A will be listed as a contingency in the Interconnection Customer's Generator Interconnection Agreement until it is accepted. Also, projects that are identified within one year will also be incorporated into the Generator Interconnection Agreement of the relevant generators.

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[317] Filing Parties October 18, 2010 Answer at 35.

3. Commission Determination

260. We accept Filing Parties' proposal for a $20 million minimum project cost to establish eligibility for 100-percent regional cost sharing. Filing Parties state that of all the Baseline Reliability Projects approved in MTEP06 to MTEP09 or pending approval in MTEP10, only 34 percent have had a total cost exceeding $20 million.[318] We believe that this threshold provides additional assurance that the MVP's benefits will be material to the region.

261. While we understand OCC's concern that projects should have substantial regional benefits before being allocated on a postage-stamp basis, the Commission is also concerned that rejecting the 5-percent net plant alternative will unduly discriminate against smaller transmission systems. We reject the calls of parties to raise the minimum cost threshold to $50 million because we believe such a change would inappropriately limit application of MVP cost sharing to projects that would otherwise meet the MVP criterion. However, Midwest ISO should evaluate, on an on-going basis, whether the $20 million threshold remains appropriate for the purpose of ensuring that projects provide material benefits to the region.

262. We find that there is insufficient evidence to conclude that MVP Criterion 2 projects will subsume or otherwise render the Market Efficiency Project cost allocation methodology obsolete. Criterion 2 guards against a project that provides a type of economic value confined to a localized area. For example, a transmission project that provides congestion relief in a single pricing zone would not qualify as an MVP because only one type of economic benefit is produced (i.e., production cost savings), with benefits accruing to load in only a single pricing zone. However, even if the benefits accrued to two or three pricing zones, the project would still not qualify as an MVP because the sole economic benefit is limited to production cost savings in a local area bordering two or three pricing zones.[319] The Criterion 2 methodology contrasts with a Market Efficiency Project cost allocation method that is designed to allocate the costs of local, economically efficient projects to the identifiable beneficiaries of those projects. That 20 percent of the costs associated with Market Efficiency Projects with a voltage rating of 345 kV and higher is allocated regionally is not inconsistent with the idea of allocating the majority of costs of local, economically efficient projects to local beneficiaries. We further note that the cost threshold of the Market Efficiency Project is $5 million whereas the cost threshold for the MVP is $20 million. Finally, we note that

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[318] *Id.*

[319] *Id.* at 31.

Midwest ISO has indicated that the Market Efficiency Project category is being reviewed by Midwest ISO and its stakeholders.

263. We find that there is insufficient evidence to conclude that MVP Criterion 3 projects will subsume or otherwise render the Baseline Reliability Project cost allocation methodology obsolete. We note that the cost threshold of the Baseline Reliability Project is $5 million whereas the cost threshold for the MVP is $20 million. Projects qualifying as Baseline Reliability Projects with capital costs less than $20 million will not qualify as MVPs, unless they are 5 percent of the constructing transmission owners net transmission plant. In this regard, Filing Parties note that for Baseline Reliability Projects approved in MTEP 06 to MTEP 09 or pending approval in MTEP 10, only 34 percent of the projects had a total cost exceeding $20 million. Additionally, a Baseline Reliability Project that costs more than $20 million can only qualify as an MVP under Criterion 3 if it provides economic benefits over a twenty year period in excess of the annual revenue requirements of the project over twenty years on a present value basis (i.e., must have a benefit-to-cost ratio greater than 1.0 considering only the economic benefits based on Criterion 3. Many projects will qualify as Baseline Reliability Projects and, while possibly providing economic benefits, will not meet the benefit-to-cost ratio test for MVPs.[320] The Baseline Reliability Project cost allocation method is designed to allocate the costs of local reliability projects to the identifiable beneficiaries of those projects as determined by the Line Outage Distribution Factor methodology. That 20 percent of these costs associated with Baseline Reliability Projects with a voltage rating of 345 kV and higher is allocated regionally is not inconsistent with the idea of allocating local reliability projects to local beneficiaries.

264. We will not require Filing Parties to remove or modify the proposed requirement that projects driven solely by generator interconnection or transmission service requests not be included as MVPs. We believe that the proposed criteria are appropriate given the different nature of these processes in Midwest ISO – the transmission planning process will have a regional outlook whereas the generator interconnection process is largely reactive to requests for interconnection. However, we note that the fact that these processes are different does not prevent customers in the interconnection and transmission service queues from benefiting from MVPs.

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[320] *Id.* at 35-36.

C. Proposals Regarding Generator Interconnection Cost Allocation and Planning Processes

1. 90-Percent Participant Funding and Shared Network Upgrades

265. Under Filing Parties' proposal, the interconnection customer will continue to pay 100 percent of the costs of network upgrades to the transmission owner in advance, subject to reimbursement under Attachment FF of the Tariff. (The level of reimbursement is generally 10 percent for the cost of required network upgrades rated at 345 kV or above; there is neither cost reimbursement nor cost sharing for Network Upgrades rated below 345 kV.)[321] The transmission owner may select one of two repayment options through which to reimburse the customer.

266. Filing Parties propose revisions to Attachment X and Attachment FF of the Midwest ISO Tariff to require later-coming interconnection customers who benefit from network upgrades built by an earlier interconnection customer to pay a portion of the costs of the upgrades that qualify as SNUs. Filing Parties state that without such contributions, interconnecting generators confront a "first mover/free rider" problem (i.e., only the first party to interconnect must pay, so subsequent generators use their upgrades at no additional charge). Network upgrades that are eligible for designation as SNUs are those that: 1) have a Generator Interconnection Agreement effective date that is after July 15, 2010; 2) have an actual in-service date that is less than five years from the date of a System Impact Study that identifies them as being eligible for contribution; and 3) Midwest ISO has determined to benefit a later-interconnected interconnection customer.[322] The later-interconnected generator or generators will contribute to the cost of the SNU in proportion to its use of the upgrade.

267. As described above, Filing Parties expect that some projects that would have been characterized as network upgrades in the past may fall under the new MVP category. Under the proposal, the remaining network upgrade projects will be subject to the existing cost allocation methodology and the cost allocation percentages will not change. Midwest ISO states that as a result of the Tariff revisions, it expects an overall reduction in the total costs allocated to generator interconnection customers as a whole, relative to current rules, because some of these network upgrades will qualify as MVPs. Also, Midwest ISO states that some network upgrades financed by first movers may become eligible for cost sharing as SNUs thereby further reducing the financial impact on generator interconnection customers.

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[321] Exceptions to this policy have been granted to ITC, and METC, and ATC.

[322] Filing Parties July 15, 2010 Filing, Transmittal Letter at 31-32.

a. Comments

268. Xcel supports retaining the interim GIP cost allocation methodology. It states that allocating costs of network upgrades to generators provides protection from disproportionate allocation of costs to customers in close geographic proximity to upgrades.[323]

269. Xcel adds that the introduction of the MVP category of facilities will limit the scope of GIP network upgrades to facilities that resolve local issues associated with interconnection. Xcel believes that the combination of 100-percent socialization of MVPs and direct assignment of GIP facilities sends appropriate price signals to generation developers to locate resources close to the existing transmission system or MVP facilities.[324]

270. Iowa Board generally supports Filing Parties' proposal. However, it argues that rolling network upgrades into MVPs gives developers an incentive to argue for accelerated MVP expansion in order to avoid directly assigned costs under the GIP process. Iowa Board recommends that Midwest ISO specify a "scope" and "pace" for MVP development of at least 2-3 years between MVP build outs.[325]

271. Many other commenters request changes to the interim cost allocation policy. ITC Companies-Wolverine, Midwest Generators, and AWEA-WOW state that the GIP cost allocation policy was approved only on an interim basis. AWEA-WOW believe that direct assignment of most costs for GIP facilities is not roughly commensurate with benefits accrued; ITC Companies-Wolverine and Midwest Generators find the GIP cost allocation, on a long-term basis, to be inconsistent with cost causation principles.[326] E.ON also states that Filing Parties ignore precedent that requires that costs be roughly commensurate with benefits.[327] E.ON claims that because GIP facilities are part of an

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[323] Xcel Comments at 13-14.

[324] *Id.* at 14-15.

[325] Iowa Board Comments at 7-10.

[326] Specifically, Midwest Generators state that, on a long-term basis, the GIP cost allocation methodology unjustly and unreasonably allocates costs of network upgrades to generators rather than the true beneficiaries of those upgrades. Midwest Generators Comments at 8-9.

[327] E.ON Comments at 30 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559).

integrated transmission system, it is inconsistent with cost causation principles to allocate all costs to interconnecting generators. In addition, Midwest Generators claims that the GIP cost allocation methodology is inconsistent with Commission precedent. They contend that direct assignment of network upgrade costs to generators does not ensure that costs are commensurate with benefits, and uses exclusive participant funding in direct contradiction of the Transmission NOPR.

272. E.ON argues that Filing Parties fail to demonstrate that the Commission should apply "regional flexibility" under the "independent entity" standard in Order No. 890 to allow the retention of the 90-100 percent direct assignment provision.[328] ITC Companies-Wolverine add that the GIP cost allocation methodology disadvantages new generation resources and independent power producers, and cannot be justified as a "regional entity" variation from Order No. 2003. Accordingly, ITC Companies-Wolverine request that the Commission require Midwest ISO to revert to the *pro forma* cost allocation methodology under Order No. 2003 until Midwest ISO develops something more consistent with the Transmission NOPR and the MVP cost allocation methodology.[329]

273. E.ON believes that "underlying circumstances" no longer justify direct allocation of costs to interconnection customers. It states that Filing Parties have developed a means to correct disproportionate impacts and recover costs for large transmission upgrades. Rather than retain the current cost allocation methodology, E.ON recommends that costs of GIP facilities be allocated system-wide as well.[330] AWEA-WOW contend that because load benefits from network upgrades, it is inappropriate to treat these facilities as "sole use" facilities.[331]

274. Furthermore, Midwest Generators argue that the GIP cost allocation methodology is not necessary to avoid disproportionate allocation of costs to transmission zones. Midwest Generators insist that an appropriate methodology ensures that the costs of all network upgrades are allocated to beneficiaries, not just costs of MVPs.[332]

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[328] *Id*. at 25-31.

[329] ITC Companies-Wolverine Comments at 9-11.

[330] E.ON Comments at 19-21.

[331] AWEA-WOW Comments at 35-40.

[332] Midwest Generators Comments at 11-12.

275. Midwest Generators also claim that direct assignment of costs would increase energy cost for consumers, eliminating many of the benefits of renewable generation. Midwest Generators state that costs of non-MVP network upgrades are ultimately reflected in power purchase agreements, potentially pricing wind resources out of the market and creating a significant financial obstacle to generators in areas not near an MVP facility.[333]

276. Midwest Generators assert that interconnection customers will not receive proper price signals from MVP facilities in a timely manner. Because of the time required to designate a project as an MVP, developers will be forced to make siting decisions without knowing whether their projects will benefit from MVPs. Midwest Generators believe that this would not be a problem if costs of network upgrades were allocated to their true beneficiaries.[334]

277. Midwest Generators further argue that the GIP cost allocation methodology contradicts state policy recognizing the benefits of renewable energy to load. For this and the above reasons, Midwest Generators request that the Commission require Midwest ISO to develop a mechanism to allocate costs of non-MVP facilities to load that benefit from generator interconnection.[335]

278. Midwest Generators further state that Filing Parties overstate the impact of MVPs on generator interconnection costs as justification for retaining the GIP cost allocation methodology. Midwest Generators assert that Filing Parties mistakenly assume that MVPs would have otherwise been directly allocated to interconnection customers, when in reality it is unlikely Midwest ISO would be able to demonstrate that the facilities meet the "but for" standard.[336]

279. E.ON asserts that Filing Parties cannot justify retaining the GIP cost allocation methodology based on the potential cost mitigation provided by the MVP and SNU facility classifications.[337] E.ON identifies four alleged practical shortcomings of Filing Parties' proposal with regard to mitigation of direct assignment costs. First, E.ON claims that the strict MVP criteria will prevent many projects from qualifying as MVPs, thereby

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[333] *Id*. at 12.

[334] *Id*. at 13-14.

[335] *Id.* at 14.

[336] *Id*. at 10-11.

[337] E.ON Comments at 21.

lowering the mitigation value. Second, E.ON states that because it will be at least five years before the first MVP comes into commercial operation, the potential mitigation will be substantially delayed. Third, E.ON alleges that the actual mitigation benefits of MVPs are speculative, as there is no guarantee that a developer will choose to site a project next to an MVP. Finally, E.ON states that the SNU process would mitigate direct assignment costs for a project only insofar as other developers choose to site their own projects nearby.[338]

280. E.ON also claims that Filing Parties have not considered the extent to which direct assignment of costs to generators causes market inefficiencies or market distortions. It states that Filing Parties discarded an injection/withdrawal methodology that allocated 20 percent of costs to generators because of market distortions resulting from direct assignment costs. E.ON believes that the same concerns apply to 90-percent/100-percent direct assignment as well.[339]

281. E.ON asserts that direct assignment of costs creates a "free rider" problem, as not all beneficiaries of GIP facilities would bear costs for their construction. Because generators would be forced to recover the cost of network upgrades through power sales, E.ON states that a single entity would be forced to effectively subsidize all of Midwest ISO system users' "beneficial reliance on that facility."[340]

282. E.ON also states that direct allocation of costs for GIP facilities perpetuates barriers to entry for transmission and generation development. Interconnection requests faced with large direct assignment costs would be forced to drop out of the queue, resulting in lower wind penetration and decreasing transmission construction. E.ON asserts that the SNU concept will not significantly reduce these barriers, as generators will still be forced to bear all costs initially.[341]

283. E.ON's preferred remedy is that the Commission require Midwest ISO to allocate 100 percent of costs of integrated transmission facilities to all Midwest ISO system users. In the alternative, E.ON asks the Commission to require Midwest ISO to revert back to allocating 50 percent of costs of integrated transmission facilities to all Midwest ISO

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[338] *Id*. at 21-25.

[339] *Id*. at 31-33.

[340] *Id.* at 33-34.

[341] *Id.* at 35-37.

system users. E.ON suggests that these remedies would create an appropriate balance between beneficiaries and costs, and eliminate market distortions.[342]

284. Edison Mission states that Filing Parties' own witness agreed that 345 kV was not a justifiable cutoff for cost allocation purposes. Network upgrades at lower voltages, such as 230 kV or 161 kV, also serve regional purposes. Accordingly, Edison Mission requests that the Commission require regional cost sharing for GIP facilities at or above 161 kV.[343] Edison Mission also asserts that 10-percent regional allocation is a *de minimis* value, and requests that the Commission require Filing Parties to allocate at least 25 percent of the cost of facilities to load.[344]

285. ITC Companies-Wolverine assert that the creation of the MVP category means that the rationale behind Midwest ISO's GIP cost allocation methodology is no longer applicable. ITC Companies-Wolverine state that participant funding for network upgrades necessary to interconnect generators is inconsistent with both the objective of Filing Parties' proposal and the cost allocation principles from the Transmission NOPR.[345]

286. AWEA-WOW argue that the reimbursement options for network upgrades impose significantly different costs over time on interconnection customers. They, along with Oak Creek and Midwest Generators, ask the Commission to require Midwest ISO to give the interconnection customer the right to select which reimbursement option applies to the customer.[346]

287. E.ON claims that giving the transmission owner the right to choose the method of reimbursement is unjust, unreasonable and unduly discriminatory. First, because the transmission owner is not independent, these provisions do not meet the independent entity variation standard. Second, because the original developer pays a different amount of costs under the monthly payment option, there will be an unduly discriminatory and disparate result among similarly situated generators. Third, the options create barriers to entry by providing incentive for generators to site in zones where the transmission owner

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[342] *Id.* at 37-38.

[343] Edison Mission Comments at 21-22.

[344] *Id*. at 22.

[345] ITC Companies-Wolverine Comments at 8-9.

[346] AWEA-WOW Comments at 43-44; Oak Creek Comments at 11; Midwest Generators Comments at 18-19.

generally chooses the lump sum repayment option. Fourth, the disparate reimbursement methods and aforementioned siting incentives for the lump sum repayment option place generators subject to monthly repayment at a competitive disadvantage. Finally, the monthly payment option forces generators to pay more than they would otherwise have to, enabling unjust and unreasonable collections for transmission owners.[347]

288. Several commenters address the 100-percent reimbursement policy that is specific to ATC and ITC. Alliant faults the MVP proposal for not comprehensively addressing GIP cost allocation procedures for the entire Midwest ISO footprint. Alliant states that ATC and ITC's pricing zones allow for 100-percent reimbursement to the interconnection customer regardless of whether it has exercised discipline in siting its facilities. Alliant states that maintaining such cost allocation in ATC and ITC's pricing zones clearly and unduly discriminates against ATC and ITC's load rather than charging the party that benefits the most from such projects, the generator. For example, if a potential generator is considering two alternate and otherwise comparable siting locations, one in the Xcel footprint and one in the ITC Midwest footprint, the generator would recognize a significantly lower total cost of siting in the ITC Midwest footprint because all of the GIP costs would be passed along to ITC Midwest load rather being charged to the generator.[348] Wisconsin Industrials claims that ATC's 100-percent reimbursement policy provides wind developers an incentive to site generators in Wisconsin regardless of whether it is an efficient siting location or not.

289. Wisconsin Industrials prefers that the Commission eliminate ATC's 100-percent reimbursement policy and replace it with the generic 90-percent/10-percent allocation methodology used by the rest of Midwest ISO (excluding ITC).[349] Alliant suggests that the Commission require ATC and ITC to submit proposed revisions to their respective GIP reimbursement policies to conform to the proposal in this proceeding. If the Commission believes that there is insufficient information or legal basis in this record to require ATC and ITC to file conforming changes to their GIP Network Upgrade reimbursement policies, Alliant suggests that the Commission require Filing Parties to submit a compliance filing prior to the Commission's final decision in this proceeding that would provide an analysis of the relative prospective impact of the disparate reimbursement processes based on information available from the Midwest ISO generation interconnection queue for ATC and ITC's footprints. Alliant believes that such an analysis would provide the Commission with a more complete understanding of

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[347] E.ON Comments at 42-51.

[348] Alliant Comments at 13-17.

[349] Wisconsin Industrials Comments at 18-22.

the cost implications of the proposal in this proceeding and would further clarify that the disparate treatment results in the unintended consequence of disproportionate GIP Network Upgrade costs being allocated to the network transmission customers of ATC and ITC.[350]

290. Iowa Board also states that the continued allowance made to ATC and ITC for 100-percent reimbursement of network upgrades under the GIP process creates distortions in generation siting and selectively eliminates Filing Parties' intended price signals. Therefore, Iowa Board further recommends that continuing allowance of 100-percent reimbursements should be contingent upon state-specific approval.[351] Similarly, Wisconsin Commission asserts that ATC's 100-percent reimbursement policy results in unjust and unreasonable charges to ATC ratepayers. Wisconsin Commission states that this policy sends inefficient pricing signals to generators, and may result in ATC's customers subsidizing generator interconnection in other states through construction of network upgrades in their own zone. Accordingly, Wisconsin Commission requests that the Commission eliminate 100-percent reimbursement policies for transmission owners in Midwest ISO.[352]

291. Michigan Commission supports continuation of existing cost allocation methodologies for network upgrades necessary for generator interconnection. It specifically supports the 100-percent reimbursement policy for the ITC, ATC, and METC pricing zones for qualified network upgrades.[353]

292. Other comments seek changes to the existing RECB processes. While MidAmerican generally supports the proposed MVP and SNU processes,[354] it asserts that the RECB II cost allocation procedures have not been working as intended. MidAmerican states that from MTEP 2006 through MTEP 2009, the RECB I cost allocation methodology for Baseline Reliability Projects shared approximately $2.48 billion; in contrast, RECB II only shared $5,655,000 between MTEP 2008 and MTEP 2009.[355]

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[350] Alliant Comments at 17-18.

[351] Iowa Board Comments at 12-14.

[352] Wisconsin Commission Comments at 10-11.

[353] Michigan Commission Comments at 18.

[354] MidAmerican Comments at 24-25.

[355] *Id.* at 18-19.

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293. MidAmerican asks the Commission to require Midwest ISO to revise the RECB II cost allocation methodology to meet the requirements of the Transmission NOPR and submit a compliance filing within one year. Alternatively, MidAmerican requests that the Commission "require the Midwest ISO to modify the RECB II cost allocation methodology to incorporate a benefit/cost ratio hurdle of 1.0:1."[356]

294. Wisconsin Commission states that it is unclear what projects would be designated as GIPs. Wisconsin Commission believes that further clarification to the GIP definition is necessary.[357]

295. AWEA-WOW support the SNU mechanism to address the "first mover/late comer" issue,[358] arguing that it will help to ensure that cost allocation is more accurately aligned with the benefits of generator-funded upgrades when additional parties come online and benefit from upgrades funded by first movers. AWEA-WOW recommend amending the process by extending it from 5 to 10 years after the online date of network upgrades that are later determined to be SNUs, as future generators would benefit from the upgrade beyond the first five years from the time the generation comes online. AWEA-WOW also suggest providing a mechanism that would identify transmission service requests and new load additions that benefit from upgrades that others fund, and requiring those additional parties to contribute the costs of SNUs. Finally, AWEA-WOW ask the Commission to require Midwest ISO to allow the generator, not the transmission owner, to decide whether the generator is paid for network upgrades under Option 1 or Option 2.

296. E.ON states that Filing Parties inappropriately justify the five-year period for SNU cost allocation using a transmission planning concept, the near-term planning horizon. E.ON asserts that the benefits provided over the full life of a project (generally 30-40 years) and the length of time required to build an MVP facility require a longer period for SNU cost allocation, such as ten years.[359]

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[356] *Id.* at 20.

[357] Wisconsin Commission Comments at 9.

[358] Commenters use several variations on this term, including "late comer/free rider," and "first mover/free rider." For simplicity, we refer to the issue as "first mover/late comer."

[359] E.ON Comments at 39-42.

297. Xcel states that Filing Parties' proposal mitigates the "first mover/free rider" issue because later interconnection customers who benefit from or impact upgrades within 5 years are assessed a portion of the cost of these upgrades. This, Xcel says, ensures that the cost of generator interconnection network upgrades are allocated both to those who cause the upgrade and those who benefit from them; moreover, the five-year time limit is appropriate to provide cost transparency for generators that initially fund SNUs and generators that interconnect later.

298. Xcel notes that the proposal also mitigates the timing risk associated with projects that have been identified as GIP network upgrades required for a customer's or customers' interconnection, but which are also under consideration as MTEP projects. Xcel states that under the proposal, an identified GIP network upgrade that is ripe for approval in the MTEP process would be included in the Generator Interconnection Agreement, and noted as a contingency that may require interconnection customer funding. If the upgrade is approved and receives cost allocation in MTEP within a specified period of time, then the upgrade will be funded pursuant to its MTEP cost allocation designation, and Midwest ISO will amend the Generator Interconnection Agreement to remove the funding contingency.

299. Xcel also contends that the filing presents an equitable, balanced proposal for cost allocation associated with MVPs and SNUs, and proposed other enhancements to the generator interconnection queue process. Xcel states that the proposed Tariff revisions are generally supported by many stakeholders and state regulatory agencies in Midwest ISO region, and that they represent a delicate balancing act given stakeholders' competing interests. It urges the Commission to find that the proposal is a well-reasoned compromise with support across stakeholder sectors.

300. NextEra and Edison Mission argue that the test for whether the later generator needs to contribute to the earlier one is inadequate (NextEra) and creates an unreasonably high threshold (Edison Mission). NextEra and Edison Mission both take issue with the requirement of the distribution factor having to exceed 20 percent. NextEra notes that this is higher than the test used to evaluate the initial interconnection. It notes that under "system intact" conditions, Midwest ISO proposes to use a 20-percent impact test for SNUs, but only a 5-percent impact test for determining whether the network upgrade was needed in the first place. Edison Mission states that the screen is 5 percent or 10 percent in PJM and in NYISO.

301. NextEra and Edison Mission each express concern that these tests will inhibit cost sharing, either by decreasing the number of later-identified interconnection customers that will be identified to share SNU costs, or by inhibiting findings that an SNU exists. NextEra says that Midwest ISO's proffered justification does not justify the disparate treatment of the first mover from the late comer, while Edison Mission contends that this does not equitably assign costs to all beneficiaries. NextEra suggests that the

Commission require Midwest ISO to modify the proposal to address the free rider issue, and that the most equitable way to do this is to use the same sensitivity test for SNUs and for Network Upgrades. Similarly, Edison Mission asks the Commission to direct Midwest ISO to: 1) use a 5-percent distribution factor screen to determine whether a later-identified interconnection customer benefits from an SNU; 2) give the first-moving interconnection customer, not the transmission owner, the choice of selecting between SNU repayment Option 1 and Option 2; 3) clarify that Network Upgrades funded by interconnection customers through a Facilities Construction Agreement or Multi-Party Facilities Construction Agreement with an effective date after July 15, 2010 are eligible for SNU status; and 4) develop a method for determining whether transmission service customers and new load additions benefit from SNUs and revise the Tariff to implement cost sharing by transmission service customers and new load additions, as well as later-identified interconnection customers.

302. Integrys recommends modifications to the SNU provisions to broaden the SNU cost sharing beyond subsequent interconnecting generators to include all beneficiaries of the network upgrades. It contends that the SNU provisions are the sole means for equitable cost sharing for non-MVP network upgrades financed by a particular generator but beneficial to broad classes of transmission system users. Integrys argues that the provisions arbitrarily restrict cost sharing to new generation interconnection customers, when multiple current and yet-unknown future users of the transmission system are likely to benefit from network upgrades built to accommodate new generation. It contends that SNU principles require that the generator causing the upgrade to be built recover that portion of the network cost from all current and future beneficiaries, and that it is arbitrary and unreasonable to require such cost sharing for MVPs and not for smaller upgrades that also provide multiple benefits. While the SNU cost-sharing is "simple in concept and of obvious equity,"[360] Integrys advocates that the Commission order accepting the MVP and GIP Tariff provisions direct Midwest ISO to submit Tariff amendments to include as SNU cost-payers all beneficiaries of network upgrades, especially those that have not qualified for MVP status.

303. Wisconsin Industrials note that Filing Parties have made considerable attempts to lesson the burden for generator interconnection projects to address the "first mover/late comer" issue by providing for projects that join the queue later than the first movers to share in the cost of network upgrades. Wisconsin Industrials argue that this approach is fair, and that it should be used to cover all costs caused by generator interconnection projects, including those that are now being proposed as MVPs. Wisconsin Industrials contend that by designating transmission investments as MVPs that were previously

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[360] Integrys Comments at 14.

considered interconnection upgrades, Filing Parties are creating another major free rider issue where the generator interconnection projects will be free riders to the load that would underwrite this investment.

b. Answers

304. MidAmerican answers that reducing the allocation of costs for network upgrades to interconnection customers increases the potential for inefficient generation development.[361]

305. In their answer, Filing Parties reaffirm theirs statement that the circumstances underlying the interim GIP cost allocation proposal still exist. Filing Parties argue that the ratio of megawatts of interconnection requests to load in western zones remains unacceptably high, making direct assignment of costs to generators necessary.[362]

306. Furthermore, Filing Parties state that placing most costs on the generator upfront, with costs possibly shifted to later interconnecting generators through the SNU mechanism, is reasonable considering that PJM customers pay the full cost of interconnection.[363]

307. Filing Parties also answer that changes to cost allocation measures place generators under different rules, but that this is not necessarily inappropriate. As an example, Filing Parties refer to the previous change in cost allocation procedures from 100-percent reimbursement to 50/50.[364]

308. Filing Parties assert that the GIP cost allocation methodology is not full participant funding, because it only assigns costs that are not shared to generators. Overall, Filing Parties believe that the combination of MVPs and SNUs will reduce the overall financial burden on generators.[365]

309. In addition, Filing Parties state that the SNU and Common Use Upgrade processes track current and future beneficiaries in a timely manner. As such, Filing Parties believe

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[361] MidAmerican October 8, 2010 Answer at 3-4.

[362] Filing Parties October 18, 2010 Answer at 55-56.

[363] *Id.* at 56.

[364] *Id.* at 57.

[365] *Id.* at 57-58.

that Filing Parties' proposal allows participants, investors, and others to make facility construction choices on an informed basis.[366]

310. Filing Parties also argue that it is not obligated to guarantee what upgrades will be proposed as MVPs or how they will be funded, and therefore the proposal is not overly speculative.[367]

311. Furthermore, Filing Parties state that the 10-percent allocation to load for facilities 345 kV and above is derived from the 20-percent postage-stamp allocation for Baseline Reliability Projects of the same voltage. Filing Parties state that this proposal merely retains the regional allocation from the 50/50 cost allocation methodology, where 10 percent was 20 percent of the 50 percent reimbursed to the generator. Filing Parties assert that because Baseline Reliability Projects below 345 kV do not get postage-stamp allocation, it is appropriate that GIP facilities below 345 kV are treated similarly.[368]

312. Filing Parties claim that the Commission has previously allowed Midwest ISO to deviate from the *pro forma* cost allocation methodology, and Filing Parties have shown that their proposal meets the independent entity variation standard. As such, Filing Parties believe that it is not necessary to require Midwest ISO to use the *pro forma* cost allocation methodology.[369]

313. In addition, Filing Parties state that the right of a transmission owner to select the reimbursement method for network upgrades was established during the original RECB filing. Filing Parties assert that the proposal does not modify these procedures outside of adapting them to the SNU process, and that commenters have not shown that transmission owners have selected reimbursement methods in a unduly discriminatory manner.[370] Filing Parties claim that the Commission considered, and rejected, arguments that these provisions are contrary to Order No. 2003 in the original RECB filing.[371]

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[366] *Id.* at 58.

[367] *Id.* at 58-59.

[368] *Id.* at 59-60.

[369] *Id.* at 60-61.

[370] *Id.* at 85-87.

[371] *Id.*

314. E.ON disagrees with Midwest ISO's answer regarding the transmission owner's right to choose the method of reimbursement. E.ON states that there was never any direct challenge to these provisions in the original RECB filing, so the Commission could not have rejected any arguments at that time. In addition, E.ON argues that while there is no evidence that transmission owners have used this right in an unduly discriminatory manner, the opportunity to do so still exists and must be addressed. E.ON claims that regardless of whether arguments against the repayment provisions represent collateral attacks, the Commission retains the authority to assess whether approved tariff provisions remain just and reasonable pursuant to FPA section 206.[372]

315. Filing Parties also reply that because ATC and ITC's methodologies have been approved by the Commission and because the instant proposal includes no changes to those approved methods, it would be inappropriate for the Commission to entertain such changes in this proceeding.[373]

316. E.ON argues that Filing Parties' proposal is noncompliant with the Commission's directives in Docket No. ER09-1431-000. E.ON states that Filing Parties' answer does not provide any information not included in the informational reports submitted in Docket No. ER09-1431-000, and at no point did Filing Parties attempt to identify benefits to load, generators, and other entities as directed by the Commission.[374]

317. E.ON also asserts that Filing Parties' proposal is inconsistent with cost causation principles. E.ON claims that Filing Parties justified the MVP process through the system benefits of an integrated system and regional usage of MVP facilities, while ignoring the fact that GIP upgrades have a similar impact. Accordingly, E.ON believes that Filing Parties have not and cannot show that load and other entities receive no benefits from GIP facilities.[375]

318. Furthermore, E.ON states that Filing Parties mischaracterize the "but for" standard as requiring direct assignment of network upgrade costs to generators. Rather, the "but for" standard requires interconnection customers to initially fund network upgrades, and

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[372] E.ON November 2, 2010 Answer at 21-27.

[373] Filing Parties October 18, 2010 Answer at 87-88.

[374] E.ON November 2, 2010 Answer at 4-6 (citing October 23, 2009 Order, 129 FERC ¶ 61,060 at P 55-56).

[375] *Id*. at 6-10.

then receive 100-percent reimbursement. E.ON argues that Filing Parties have not shown their proposal to be consistent with the "but for" standard.[376]

319. In addition, E.ON states that Filing Parties' proposal is not acceptable under the independent entity variation standard. E.ON explains that an RTO must show its proposal produces just and reasonable rates and Filing Parties have not done so.[377]

320. E.ON also argues that the occurrence of large amounts of interconnection requests in comparison to load in western Midwest ISO does not justify direct assignment of costs for network upgrades to generators. E.ON claims that Midwest ISO is simply changing one disproportionate methodology for another. E.ON believes that an appropriate cost allocation methodology would attract investment capital to develop Midwest ISO's abundant wind resources. E.ON states that the previous 50/50 cost allocation methodology is an appropriate mechanism.[378]

321. E.ON further states that the mitigating impacts of MVPs and SNUs cost allocation does not cure the cost causation deficiency of the GIP cost allocation methodology for a number of reasons. First, E.ON claims that the GIP cost allocation methodology must be judged on its own merits. Second, there is no guarantee a transmission project will be designated as an MVP. Indeed, E.ON argues that two thirds of the transmission projects do not meet the cost threshold, and will therefore provide no mitigation benefits. Third, E.ON states that because it may be between five and ten years before the first MVP facility comes into commercial operation, the potential mitigation value is not available to generators ready to interconnect now. Finally, E.ON asserts that the SNU proposal is limited and only mitigates costs if other developers choose to site their own projects near a facility assigned to the original interconnection customer. Accordingly, E.ON reiterates its argument that the mitigation benefits of MVPs and SNUs cost allocation are merely speculative and do not justify retaining the GIP cost allocation methodology.[379]

322. Iberdrola-Invenergy state that the reimbursement method selected by the transmission owner has a significant impact on project developers. Iberdrola-Invenergy explain that the monthly charge option creates uncertainty for developers, as the charge is based on the transmission owners' fixed charge rate and can vary from one year to the

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[376] *Id.* at 10-11.

[377] *Id.* at 11-12.

[378] *Id.* at 12-14.

[379] *Id.* at 14-17.

next. Iberdrola-Invenergy argue that because the transmission owners should be indifferent to the reimbursement method selected, it is reasonable that the interconnection customer have the right to choose.[380]

323. Iberdrola-Invenergy assert that the introduction of the SNU process makes it even more important that the interconnection customer have the right to choose the reimbursement method. Iberdrola-Invenergy note that the choice of reimbursement method appears to impact the material cost responsibility for generators subject to SNU allocation, as a later interconnecting generator may pay less under the monthly charge option than the lump payment option. Iberdrola-Invenergy also claim that the current provisions prevent an interconnection customer from making the most efficient reimbursement choice when considering the impacts of projects that may utilize capacity created by SNUs.[381]

324. Iberdrola-Invenergy argue that advance knowledge of the reimbursement method does not provide certainty regarding the amount reimbursed, especially when considering the new SNU process. Iberdrola-Invenergy believe that the entity bearing the financial risk should be entitled to choose how it is reimbursed, and repeats their request to allow the interconnection customer to select the reimbursement method.[382]

325. Iberdrola-Invenergy state that the right of the transmission owner to choose the reimbursement method is properly before the Commission because the revisions made to accommodate the SNU process change the costs that may be assigned to the interconnection customer. Iberdrola-Invenergy assert that the Commission has the obligation and authority to review the entirety of a new rate regime, including both cost allocation and compensation.[383]

326. Regarding SNUs, Filing Parties disagree with AWEA-WOW's proposal to use a ten-year, rather than a five-year, period for the second criteria for SNU designation (i.e., to deem generators eligible for contribution if their system impact study is completed less than ten years from that of the network upgrade that benefits them) saying that the ten-year period goes beyond the planning cycle and is too complex. Filing Parties contend

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[380] Iberdrola-Invenergy November 2, 2010 Answer at 3-5.

[381] *Id.* at 5-6.

[382] *Id.* at 6-7.

[383] *Id.* at 7-9.

that because the planning horizon for generator interconnection is five years, it is sensible to limit the SNU designation to that time period.

327. E.ON opposes Filing Parties' answer and states that a ten year period would be reasonable. E.ON reiterates that the SNU is a cost allocation concept, not a planning concept, and network upgrades typically have a useful life much longer than five years. E.ON also argues that Filing Parties have not shown that a ten year period would be more complex than a five year period, and at any rate the Commission has disregarded issues of complexity in independent entity variation cases before. Accordingly, E.ON asserts that Filing Parties have provided no basis for not extending the availability period to ten years. Indeed, E.ON claims that such extension is necessary to offset the direct assignment of costs generators must bear.[384]

328. Filing Parties defends the use of a 20-percent, rather than a 5-percent, distribution factor screen for determining SNUs because the test for SNUs differs from the test for an impact on the transmission system. It argues that using 5 percent for both screens would compare the first mover and the late comer on a level playing field to determine their impact on causing the initial constraint, whereas the 20-percent distribution factor for the late comer project evaluates whether that project derives sufficient benefit from the upgrade to contribute to it. Therefore, the test is not whether the late comer would have caused a problem, but whether the late comer benefits from the solution that the first mover funded.

329. In response to arguments that additional potential beneficiaries should share in the cost of SNUs, Filing Parties state that entities other than interconnection customers should not be assessed costs because the SNU is an expansion of the generating facility network upgrade concept and is consistent with Order No. 2003. Filing Parties point out that generators remain for the length of their useful life, while transmission service requests are temporary in nature. It adds that if this argument was applied to larger upgrades, then one could claim that if load or a transmission customer should help pay for a SNU, then it should also contribute to the costs of network upgrades, Baseline Reliability Projects, Market Efficiency Projects, and even MVPs. This was not the intent underlying Filing Parties' filing.

330. In response to Edison Mission, Filing Parties clarify that they intended for network upgrades funded by interconnection customers through a Facilities Construction Agreement or Multi-Party Facilities Construction Agreement are eligible for SNU status.

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[384] E.ON November 2, 2010 Answer at 19-21 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 15).

331. In response to Iberdrola-Invenergy, Filing Parties state that they do not propose to revise Midwest ISO's Letter of Credit requirements, and that Iberdrola-Invenergy have not shown that such changes are needed. It notes, however, that the portion of the Letter of Credit applicable to the upgrade that is later determined to be an MVP can be released when that project is listed in Appendix A. RES Americas disputes Midwest ISO's arguments, reiterating Midwest Generators' comments.

c. Commission Determination

332. The comments do not persuade us that the GIP cost allocation methodology accepted in the October 23, 2009 Order has become unjust and unreasonable, or that our approval of the MVP proposal necessitates change to the GIP cost allocation methodology. We will therefore approve Filing Parties' proposal to retain the GIP cost allocation methodology. The previously accepted GIP cost allocation remains just and reasonable, particularly when viewed as part of a package of reforms accompanying the MVP and SNU proposals.

333. Several parties challenge the GIP cost allocation methodology on the ground that the benefits of the Network Upgrades are not commensurate with the costs that the parties must bear. We disagree. The Commission explained in Order No. 2003 that independent system operators such as Midwest ISO have discretion to propose an appropriate cost allocation methodology for interconnection-related network upgrades, including providing interconnection customers with capacity rights made feasible by such projects. We note that Filing Parties' proposal does not alter the Tariff provision regarding an interconnection customer's entitlement to Financial Transmission Rights for costs not repaid.

334. We agree with Filing Parties that changes to ATC and ITC's 100-percent crediting cost allocation methodology are beyond the scope of this proceeding. We therefore reject requests by protestors to revisit these provisions.

335. We reject commenters' requests to give interconnection customers the right to select the reimbursement option for network upgrades. The provision regarding the right to select a reimbursement option was previously accepted by the Commission as just and reasonable, and Filing Parties have not proposed to revise it. It is therefore beyond the scope of this proceeding. To the extent that commenters wish to challenge the justness and reasonableness of an accepted tariff provision, the appropriate forum would be a complaint under section 206 of the FPA.[385]

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[385] 16 U.S.C. § 824e (2006).

336. We will accept the SNU proposal as just and reasonable. We agree with Filing Parties that the proper test for cost sharing with regard to an already-constructed upgrade is not what effect a late-coming generator would have had on the system as it existed prior to the upgrade, but rather whether that late-coming generator will actually benefit from the upgrade. In this light, we find that the 20-percent distribution factor screen is an appropriate measure of benefits that strikes an appropriate balance between cost sharing and guarding against overcharging late-coming generators.

337. We will not require Filing Parties to amend their proposal to accommodate Integrys' request to broaden SNU cost sharing to include other classes of transmission system users. The SNU process is not intended to shift GIP upgrade costs to classes of transmission system users that would not be eligible to share in the initial funding of the upgrade. As such, it is reasonable that SNU cost sharing only apply to interconnecting generators.

2. Coordination of Generator Interconnection Process with Transmission Planning Process

338. Under Filing Parties' proposal, the timing of milestones for the MTEP transmission planning process and generator interconnection process will remain intact. Network upgrades identified through the generator interconnection process may be allocated under the MVP methodology if the upgrade is approved for inclusion as an MVP in MTEP Appendix A within the later of one year from execution or unexecuted filing of a Generator Interconnection Agreement or the issuance of the next annual MTEP Report.[386]

a. Comments

339. Multiple parties assert that Midwest ISO needs to align the timing of milestones between the MTEP transmission planning and the generator interconnection processes in Attachment X of the Midwest ISO Tariff for better coordination and identification of potential MVPs.[387] Edison Mission states that Midwest ISO needs to determine whether network upgrades that are identified in the Attachment X process should be considered MVPs, Baseline Reliability Projects or Market Efficiency Projects as part of the MTEP transmission planning process.[388] Similarly, Edison Mission states that Midwest ISO

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[386] Filing Parties July 15, 2010 Filing, Laverty Test. at 33-34.

[387] Edison Mission Comments at 9-12; Iberdrola Comments at 18-24; NextEra Comments at 16-21; AWEA-WOW Comments at 34-35.

[388] Edison Mission Comments at 9.

needs to factor in transmission projects identified as potential MVPs, Baseline Reliability Projects or Market Efficiency Projects in the Attachment X process.[389]

340. NextEra states that Midwest ISO proposes at least three different provisions that are intended to minimize the chance that transmission projects under Attachment X become MVPs: 1) an MVP "must be *developed* through the transmission expansion planning process;" 2) the transmission project "must be evaluated through the [t]ransmission [p]rovider's transmission planning process and approved for construction by the [Midwest ISO] Board prior to the start of construction;" and 3) "[n]etwork [u]pgrades driven solely by an [i]nterconnection [r]equest, as defined in Attachment X of the Tariff, or a Transmission Service request will not be considered Multi Value Projects."[390] However, if a "project qualifies as an MVP and is recommended for construction both by the [Attachment X process] and the transmission expansion planning process *within the same planning cycle*, the project will be classified as an MVP."[391] NextEra argues that the proposal amounts to a snapshot rule: a one-time judgment of whether a transmission project under Attachment X can be an MVP.[392] That is, the timing has to be perfect for the transmission project under Attachment X to have a chance of becoming an MVP.

341. To illustrate its point that the MTEP planning process and the Attachment X process are separate and uncoordinated, Edison Mission provides a detailed explanation of the timing of these processes. It states that transmission owners propose new transmission projects to be included in the MTEP by September of each year, and such proposals are studied and vetted through a series of stakeholder meetings until Midwest ISO issues the draft MTEP report by July 15th of the following year. With input from stakeholders, Midwest ISO finalizes and submits the MTEP report to the Midwest ISO Board for review and approval by the end of the following year. In addition, Edison Mission explains that under the Attachment X process, once Midwest ISO receives a valid application, interconnection customers enter the next regularly scheduled Feasibility

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[389] *Id.* at 10.

[390] NextEra Comments at 16-17 (citing Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 4, Original Sheet Nos. 3451-3451C) (emphasis added by NextEra)).

[391] *Id.* at 16 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 32 (emphasis added by NextEra)).

[392] *Id.* at 19.

Study, which typically takes about two weeks. Upon completion of the Feasibility Study, interconnection customers generally enter the System Planning and Analysis phase, which includes a (typically) year-long System Impact Study.[393] Interconnection customers then proceed to the Definitive Planning Phase which commences twice a year and typically takes about 120 days to complete, and which includes a review of, and potentially a re-study of, the System Impact Study.[394] Finally, Edison Mission explains that upon the completion of further milestones, interconnection customers enter the Facilities Study stage of the Definitive Planning Process, which typically takes another 120 days to complete. Edison Mission argues that under the current schedules, it would be a coincidence if the MTEP transmission planning and Attachment X processes aligned with one another. Accordingly, Edison Mission urges the Commission to direct Midwest ISO to consider altering the timing of the MTEP transmission planning and Attachment X processes to permit better coordination.[395]

342. NextEra recommends a review at the end of a System Planning and Analysis phase, and/or the Definitive Planning Phase, to determine whether the facilities identified through those studies also qualify as MVPs. AWEA-WOW state that Midwest ISO transmission owners may submit a proposed transmission project for expedited treatment through the MTEP planning process in what is called an "out-of-cycle" review, allowing parties to go through the planning review and, ultimately, gain Midwest ISO Board approval for transmission additions within the current MTEP cycle rather than waiting for a future MTEP cycle. AWEA-WOW recommend that a similar process be made available to generators for reviewing projects required for interconnection that are potential recipients of MVP cost allocation treatment.[396] AWEA-WOW argue that this

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[393] Edison Mission Comments at 10-11 (Edison Mission describes the SPA phase of the System Impact Study as an ongoing study which identifies a portfolio of transmission projects in phases. Therefore, some interconnection requests waiting to be studied may enter into the SPA study sooner than their scheduled cycle start date).

[394] *Id.* at 11 (Edison Mission states upon completion of the Feasibility Study, the interconnection customer can be put onto a "fast track" directly into the Definitive Planning Phase of the System Impact Study).

[395] *Id.* For example, Edison Mission states that the Brookings 345 kV transmission line needed better coordination between the MTEP transmission planning and GIP processes. Edison Mission states that the Brookings 345 kV transmission line started out as a Baseline Reliability Project in the MTEP process, but then Midwest ISO inappropriately proposed it as a network upgrade in the GIP process for group study, and now Midwest ISO appropriately propose it as a "starter" MVP. *See id.* at 11-12.

[396] AWEA-WOW Comments at 34.

could help address the timing disconnect between the interconnection study process and the MTEP process.

343. Several parties recommend lengthening the "contingency period" to allow additional time to consider GIPs as MVPs. Edison Mission and NextEra claim that a one-year contingency period is inconsistent with the five-year MTEP planning horizon. Accordingly, they request that the window of eligibility be set at five years.[397] AWEA-WOW and Iberdrola question the length of the "contingency period" for the first set of MVPs. They state that contentious stakeholder discussions may delay approval of these MVPs beyond the contingency period. AWEA-WOW request that the initial period run through the beginning of the MTEP 2012 cycle; Iberdrola requests the beginning of the MTEP 2013 cycle.[398] Iberdrola argues that network upgrades identified in a System Impact Study or Facilities Study should not be eliminated from the MTEP Appendices and that customers should be able to retain their queue position during this contingency period.

344. Lastly, AWEA-WOW state that it is their understanding that a transmission line that supports more than one interconnection request required to meet state or federal energy policy can be considered an MVP and request that Midwest ISO clarify the proposed language in this regard. [399]

b. <u>Answers</u>

345. Filing Parties maintain that the MTEP and Attachment X processes are appropriately aligned. They argue that selecting MVPs from upgrades that solely arose from Attachment X defeats the purpose of the MVP process, which considers other factors. Filing Parties explain that the MVP designation will be made through the MTEP process,[400] and that many long transmission lines needed to integrate large quantities of location-constrained resources will likely be designated as MVPs.[401]

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[397] Edison Mission Comments at 13-14; NextEra Comments at 22.

[398] AWEA-WOW Comments at 33-34; Iberdrola Comments at 21.

[399] AWEA-WOW Comments at 32. Proposed section II.C.2.f states, "Network Upgrades driven solely by an Interconnection Request, as defined in Attachment X of the Tariff, or a Transmission Service request will not be considered [MVPs]." Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet No. 3451C.

[400] Filing Parties October 18, 2010 Answer at 62 (citing Filing Parties

(continued…)

346. Filing Parties state that the identification of projects developed and planned in the Attachment X process properly allocates costs to generators that cause the need for those upgrades, and this is consistent with the funding of network upgrades by interconnecting generators under Order No. 2003.[402] In addition, Filing Parties argue that the proposal already accounts for the possibility that upgrades identified for individual projects in the Attachment X process will also be identified (in whole or in part) as MVPs. Filing Parties state that the proposal allows for a network upgrade that is under consideration for inclusion in MTEP Appendix A to be listed as a contingency in the interconnection customer's Generator Interconnection Agreement until it is accepted and, that projects that are identified within one year will also be incorporated into the Generator Interconnection Agreement of the relevant generators.

347. Filing Parties argue that it is impractical to reevaluate a project for MVP designation or to review all GIPs to determine whether they meet MVP criteria, so an out-of-cycle review process to determine the MVP status of GIPs is impractical.[403] Filing Parties maintain that providing a one-year window for an upgrade that is listed as a contingent upgrade in a Generator Interconnection Agreement, and that is under consideration in the MTEP process as an MVP, to be approved as an MVP coincides with the annual MTEP timeframe, and provides some resolution within a reasonable timeframe as to which costs will be borne by interconnecting generators. Filing Parties

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July 15, 2010 Filing, Transmittal Letter at 30-31). *See also* October 23, 2009 Order, 129 FERC ¶ 61,060 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").

[401] *Id*. Filing Parties state that 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. *See* October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58.

[402] Filing Parties October 18, 2010 Answer at 62 (citing *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Utility Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007)).

[403] *Id*. at 63.

argue that absent some timelines, cost estimates for projects in the interconnection queue cannot be provided with any reasonable certainty.[404]

348. Filing Parties also disagree that the text in section II.C.2(f) of Attachment FF is vague.[405] Filing Parties argue that this text clearly prohibits upgrades driven solely by an interconnection request or a transmission service request from being considered as MVPs. They argue that this text does not eliminate the possibility that contingencies identified in Generator Interconnection Agreements will become MVPs, but retains the Commission standard that upgrades that would not have been needed "but for" an interconnection request are appropriately allocated to the interconnecting generator and that transmission service requests should similarly bear the costs of any upgrades needed to support their requests.[406] Moreover, Filing Parties state that projects designated as MVPs would necessarily be found to benefit other parties and would not be prevented by this language. Filing Parties state that MVP designation is intended to work together with the Attachment X process to encourage generators to locate near MVPs.

349. Integrys argues that Filing Parties use their answer to amend their proposal to adopt a "but for" test for excluding from MVP status network upgrades that are driven by interconnection service and transmission service requests.[407] Integrys argues that the Commission should reject the "but for" test because an answer cannot be used to amend a filing, and because Filing Parties have not provided any evidentiary support. Furthermore, Integrys states that Filing Parties incorrectly claim that the "but for" test simply retains a Commission-required standard. Integrys argues that Order No. 890 did not specify a cost allocation methodology, but only provided overall guidance. Integrys states that the Commission has required Midwest ISO to use a "but for" analysis for GIPs so that generators do not have the ultimate responsibility to pay for a transmission line that has multiple benefits.[408] However, Integrys argues that adopting a "but for" standard for network upgrades in the MTEP process for determining MVPs is different, and the

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[404] *Id*.

[405] *Id*. at 64.

[406] *Id*.

[407] Integrys November 2, 2010 Answer at 1, 3-4.

[408] *Id*. at 5 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559).

Commission has not mandated this standard for interconnection service or transmission service requests in an Order No. 890 planning process.[409]

c. Commission Determination

350. As noted above, and as discussed further below, we agree with Filing Parties that MVPs should be identified as part of Midwest ISO's transmission planning process. MVP designation is intended to work together with the Attachment X process to encourage generators to locate appropriately. By definition, because an MVP must be the product of regional planning and include regional stakeholder input, and must yield corresponding regional benefits, it cannot be driven by the Attachment X process. Thus, generators that locate in areas that benefit from MVPs will see a decrease in upgrade costs. Interconnecting generators in areas without proposed MVPs (i.e., areas that lack robust transmission), and whose requests drive the need for significant upgrades, will bear those costs either alone or with other interconnection customers.[410]

351. Notwithstanding the above, existing or future customers may have business cases that are not planned with MVPs in mind and may seek MVP cost allocation for their associated upgrades. If a network upgrade identified in a System Impact Study is also being considered as an MVP and is listed in MTEP Appendix B when a Generator Interconnection Agreement is finalized, there shall be a period where the project may be declared an MVP and moved to Appendix A, releasing the generator from cost responsibility. Midwest ISO will allow one year, or until the next MTEP report, for transmission upgrades (those not solely related to interconnection requests or transmission service requests) to move through the MTEP process in case they might be identified as MVPs. During this "contingency period," the network upgrade will be listed as a contingency in the Generator Interconnection Agreement until its status has been determined. If the project is not approved, the interconnection customer will be required to fund the network upgrade.[411] The one-year contingency window provides enough flexibility to ensure that upgrades that may be categorized as MVPs are appropriately categorized as MVPs. Because one year is enough time to make this determination, we decline to adopt commenters' suggestions that a five-year window (to match the length of the MTEP process) is more appropriate.

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[409] *Id*. at 5-7.

[410] Filing Parties July 15, 2010 Filing, Curran Test. at 8 and 34.

[411] *Id.*, Laverty Test. at 33-34.

352. As discussed above, a network upgrade that is under consideration for inclusion in MTEP Appendix A will also be listed as a contingency in the interconnection customer's Generator Interconnection Agreement 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. Further, without some timelines, costs estimates for projects in the queue cannot be provided with any reasonable certainty.[412]

353. We agree with Midwest ISO that it would be impractical for it to re-evaluate a project or to review all GIPs to determine whether they meet MVP criteria and, thus we find that it is also impractical to require an out-of-cycle review process to determine the MVP status of GIPs. Finally, with regard to section II.C.2.f of Attachment FF, we find that Midwest ISO's answer provides AWEA-WOW's requested confirmations and therefore addresses their concerns.

354. Finally, we disagree with Integrys that Filing Parties used their answer to amend the proposal to adopt a "but for" standard. We find that Filing Parties' Answer merely makes explicit what was implied in its proposal.

D. Cost Recovery

1. Proposed MVP Usage Rate

355. Filing Parties state that MVP costs will be recovered through a system usage (i.e., MWh) charge allocated to all load in, and exports from, Midwest ISO. The charge, called the MVP usage rate, will be used to recover the MVP annual revenue requirement from monthly withdrawals, exports, and wheel-through transactions, as described and calculated in proposed Attachment MM of the Tariff. The proposed MVP cost allocation "allocates costs based on usage over time."[413] Filing Parties further claim that the MVP cost allocation would not distort the markets, as opposed to distortions that might result from imposing a charge on generators and import transactions.

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[412] Filing Parties October 18, 2010 Answer at 30, 61-64.

[413] Filing Parties July 15, 2010 Filing, Transmittal Letter at 25. Here Midwest ISO contrasts its proposed usage charge with a demand charge.

a. Comments

356. AWEA-WOW, E.ON, and Alliant support the proposed usage charge. AWEA-WOW state that, since load is the ultimate beneficiary of electricity production, the proposed usage charge is consistent with Commission precedent. They contend that it is efficient to directly charge load for the transmission upgrades necessary to support electricity production and delivery. They claim that charging parties based on their benefits as they accrue reflects the changing nature of MVP beneficiaries over time. AWEA-WOW argue that alternative approaches (e.g., participant funding) that take a snapshot-in-time approach to beneficiaries would not reflect MVP beneficiary changes.[414] E.ON supports using a usage charge because it would ensure that the current users and beneficiaries of MVPs pay for the corresponding costs and thereby provide a closer allocation of MVP costs to actual beneficiaries than would a demand charge.

357. Alliant argues that MVP costs should be allocated on a usage basis. It contends that wind generation is expected to remain the predominant renewable energy source within Midwest ISO due to applicable renewable portfolio standards and that wind generation resources are primarily energy resources rather than capacity ones due to the relative inability to dispatch wind generation. Alliant contends that, while capacity-related rates were appropriate in previous years during which reliability concerns were the primary drivers of transmission interconnections, the use of the Midwest ISO system has evolved, and it is reasonable to achieve a balance that recognizes that "the transmission system is both for market efficiency (energy) and reliability (capacity)."[415] As a result, Alliant supports the proposed usage-based MVP cost allocation because it would balance the allocation of transmission costs within Midwest ISO between the usage-based and demand-based methods.

358. Minnesota Commission-Minnesota Security and OMS suggest that Filing Parties explore the possibility of a two-part rate design that collects some costs through the proposed usage charge and other costs through a demand charge. Minnesota Commission-Minnesota Security contend that a two-part rate design would mitigate the potential rate burdens placed on certain customer classes, while retaining the proposed usage charge's sensitivity to seasonal changes and encouragement of energy conservation efforts. Minnesota Commission-Minnesota Security add that a two-part rate design could also encourage demand response efforts to a further extent than could a usage charge

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[414] AWEA-WOW state that they would support pricing methods other than the proposed usage charge if the methods could reasonably allocate costs to beneficiaries, reflect the changing nature of those beneficiaries, and are not akin to participant funding.

[415] Alliant Comments at 9.

alone. OMS argues that charging for the costs of MVPs over time as expenses are incurred would be an improvement over the static cost assignments used in the past. OMS contends that a two-part rate design could capture "the year-round effects of the MVPs with the peak investment incentives of existing and future transmission and generation assets."[416] OMS adds that, as reserve margins become tighter, the relative split between a usage and demand charge could be adjusted to provide better relative incentives. OMS further recommends that Midwest ISO periodically review the cost allocation to ensure that it accomplishes Midwest ISO's objectives and does not impose unjust impacts on the system or customers.

359. Numerous other parties[417] oppose the proposed usage charge and argue that MVP costs should instead be recovered by using a demand charge. Several protestors maintain that the proposed usage charge is inconsistent with cost causation principles. ABATE maintains that the proposed usage charge does not reflect the incurrence of MVP costs or the associated benefits. It claims that the need for MVPs would be "driven by forecasted peak energy production in remote areas where wind generation is being located and their operation will be highly coincident."[418] ABATE also contends that the size of MVPs would be driven by peak system demand and not energy usage.

360. AF&PA contends that the proposed usage charge is divorced from any real attempt to determine cost causation and any consistent measure of benefits. According to AF&PA, the proposed usage charge would not distinguish between loads in constrained load pockets and energy withdrawn at other locations, causing customers in load pockets to subsidize transmission expansions that do not benefit them, even indirectly, and diverting investment away from potential renewable projects in constrained areas or in areas nearer to loads that lack subsidized transmission treatment. AF&PA claims that the proposed usage charge would be unrelated to the consumption of renewable energy for the purpose of satisfying any renewable portfolio standards and would apply equally to the consumption of coal-fired or other generation resources. AF&PA maintains that the proposed allocation is inconsistent with the Commission's reliance on locational capacity and energy markets to send correct price signals to customers about the cost of consumption and to allocate the cost of resources to customers in a fair manner. AF&PA adds that subsidizing transmission investments by singling out a particular type of resource would disfavor efficient siting decisions by inducing the development of stand-

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[416] OMS Comments at 9.

[417] ABATE, AF&PA, Basin, Hoosier-SIPC, Illinois Commission, Industrial Customers, ITC Companies-Wolverine, Midwest Generators, Steel Producers.

[418] ABATE Comments at 5.

alone renewable facilities rather than more efficient combined heat and power applications that could also satisfy the applicable renewable portfolio standards.

361. AF&PA argues that, if MVP costs are to be socialized, a demand charge would be more consistent with cost causation principles. It claims that transmission systems are sized to meet peak demand, regardless of the power source, and that public policy mandates to promote renewable resources will not alter this basic engineering and economic fact.[419] AF&PA believes that Midwest ISO's currently-approved demand-based transmission charges reflect this reality, consistent with cost causation principles, and it states, for example, that PJM socializes transmission costs using a flow-based demand charge.[420] AF&PA argues that allocating costs based on energy usage would be unrelated to cost causation because, at best, energy usage is arbitrarily related to transmission expansion costs. It also asserts that the fixed costs of the transmission system do not change from moment to moment and that customers should be given price signals to reflect that long-term transmission expansion costs are driven by demand. A demand charge would allow customers to consider the costs of their consumption decisions at different times, according to AF&PA, whereas a usage charge conveys to customers that they should be indifferent as to when their consumption occurs. AF&PA submits that, by sending such incorrect price signals, the proposed usage charge would subsidize inefficient consumption by other customers and hasten the need for further transmission expansion.

362. Hoosier-SIPC argue that the proposed usage charge for MVP facilities are not consistent with cost causation principles and request that, if the Commission accepts the proposal, the Commission require the MVP rate design to utilize a demand charge. Irrespective of the motivation behind their construction, they state that MVPs would be sized according to the highest amount of energy that they would be required to carry. Hoosier-SIPC maintain that it is appropriate for entities that use the lines most heavily during those peak times to pay more than entities that use the lines to a lesser degree, or not at all, during those periods. They add that Midwest ISO charges load-serving entities based on their energy withdrawals from the Midwest ISO system as a whole and not for their usage of transmission facilities. Hoosier-SIPC argue that a demand charge would reflect that MVPs would be designed to meet the overall usage of the entire system.

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[419] AF&PA Comments at 3-5.

[420] AF&PA explains that PJM socializes transmission costs more or less broadly depending on its calculation of a power distribution factor, which measures the effect of peak power flows on the need for transmission upgrades. *Id.* at 6.

363. Industrial Customers argue that Filing Parties have not demonstrated that the estimated benefits of MVPs are dependent on energy use. They contend that it is not more effective to measure system use based upon volumetric consumption than based on monthly coincident peak demands and reserved capacity. They assert that a customer's peak demand is a good proxy for its share of total system use.

364. ITC Companies-Wolverine contend that the proposed MVP rate design is not efficient because the usage of the transmission system may vary, while the costs of transmission infrastructure do not.[421] They state that, for this reason, the proposed usage charge is not well aligned with cost causation and that a demand charge should instead be used.

365. AF&PA also argues that the proposed usage charge would muddle the relationship between cost causation and energy usage. It claims that demand-related costs would be allocated based on usage at the regional level and based on demand at the local level, resulting in "a hodge-podge allocation that divorces cost causation from usage."[422] As a result, AF&PA argues that utilities allocated significant regional costs on a usage basis would be tempted to tamper with existing demand-based local allocations, which would lead to wasteful future transmission expansions and would be detrimental because the current system is "plagued by deteriorating utilization under declining system load factors."[423]

366. Several commenters contend that using a usage charge, rather than a demand charge, to allocate MVP costs would be inconsistent with other Commission precedents. Midwest Generators request that the Commission require Filing Parties to adhere to Midwest ISO's current demand-based rate design, consistent with Commission precedent that requires charges for transmission service to be developed based on annual peak demand and charged based on reservation size. Joint Protestors contend that the proposed usage charge is inconsistent with Order No. 888 and its progeny and that the proposal does not justify its departure from the Commission's requirements.[424] Joint

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[421] ITC Companies-Wolverine Comments at 15 (citing ITC Companies-Wolverine Comments, Tierney Aff. at 18-19).

[422] AF&PA Comments at 8.

[423] *Id.*

[424] Joint Protestors Comments at 29 (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats.

(continued…)

Protestors state that MVPs will not be single-use facilities for exclusive use by renewable resources because they will be integrated with existing facilities.[425] Joint Protestors claim that the integration of these facilities with existing transmission requires the continued use of the 12-month coincident peak divisor in designing the rate. They add that the costs of providing service constitute fixed costs, which are appropriately recovered using a demand charge. They state that the cost of providing the transmission necessary to transfer renewable energy is not a variable cost that will vary with the level of demand.

367. Basin argues that MVP costs should be allocated on a demand basis because peak demand, not average energy use, is considered in the planning process. Basin asserts that MTEP decisions are made primarily based on peak demand requirements, focusing on ensuring system reliability and market efficiency in meeting growth in peak load.[426] It claims that, since projects are categorized as MVPs, Baseline Reliability Projects, Regionally Beneficial Projects, or Generation Interconnection Projects only after they are chosen through the MTEP process, the categorization of a project as an MVP is not relevant to whether the decision to construct the project is more heavily driven by average transmission usage than by peak demand need. Basin argues that the charges for all MTEP projects should be developed in the same way because the projects are chosen based on the same criteria. Basin submits that MVP costs should be allocated using a demand charge, consistent with the allocation of Baseline Reliability Project and Regionally Beneficial Project costs and with the court's finding that capacity costs "are assessed to the peak-period users because it is peak demand that determines how much a utility will invest in capacity."[427] Basin adds that, while the Commission has held that

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& Regs. ¶ 31,048, at P 239, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group*, 225 F.3d 667, *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002)).

[425] Joint Protestors state that, if the transmission did, in fact, stand in isolation with the single purpose of delivering renewable energy directly to certain loads, these facilities would be distribution facilities and, as such, should not be included in the transmission rate base recovered under the Midwest ISO Tariff.

[426] Basin Comments at 4 (citing Filing Parties July 15, 2010 Filing, Webb Test. at 7; Midwest ISO Tariff, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, section 1.8).

[427] *Id.* at 5-6 (citing *Louisiana Public Service Commission v. FERC*, 184 F.3d 892, 895 (D.C. Cir. 1999) (quoting *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1198 (D.C. Cir. 1989))).

off-peak users could also pay a demand charge if "there was specific evidence that peak use did not determine investment in capacity,"[428] Filing Parties present no such evidence here.

368. Steel Producers claim that the proposed usage rate is inconsistent with the Commission's traditional treatment of transmission cost allocation. Steel Producers argue that the cost of MVPs should be allocated based on demand, not usage. They assert that demand charges better reflect that the economic value of additional transmission lines is higher during periods of peak consumption than non-peak periods because peak periods suffer more severe transmission congestion and are subject to higher transmission prices.

369. Basin, Illinois Commission, and ITC Companies-Wolverine disagree with Filing Parties' argument that the proposed usage charge would better ensure that the cost allocation changes as benefits change. Basin argues that the difference between usage and demand charges is the method of measuring benefits and that cost allocations change as benefits change regardless of whether the charges are based on usage or demand. Basin argues that a demand charge would better reflect changes in consumer demand. Illinois Commission contends that the allocation of MVP costs does not address possible changes in the use of MVPs over time because the charge is based on system usage, rather than MVP usage. ITC Companies-Wolverine argue that a demand charge may also capture differences in usage over time, as customers are billed on their actual monthly usage at the time of peak demand.

370. Basin, Illinois Commission, Industrial Customers, and Steel Producers disagree with Filing Parties' argument that the proposed usage charge would better reflect the benefits of MVPs as they accrue throughout the year. Illinois Commission argues that, under the proposed usage charge, there would be no relationship between the benefits of MVPs and the MVP cost allocation based on system usage. Industrial Customers maintain that the benefits from MVPs may occur in different hours of the year, but those benefits are not necessarily evenly distributed over all hours of the year. They state that those benefits could instead be concentrated at the time of peak system demand.[429] Basin and Steel Producers assert that Filing Parties' argument would apply equally to all MTEP projects and, therefore, would indicate that the costs of all transmission projects should be allocated based on usage, rather than peak demand. Basin argues that all transmission facilities provide benefits at times other than peak load, and therefore, Filing Parties have not demonstrated why MVP costs should not be allocated based on peak demand. Basin

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[428] *Id.* at 6; *see*, *e.g.*, June 2, 2005 Rehearing Order, 111 FERC ¶ 61,337 at P 87.

[429] Industrial Customers Comments, Dauphinais Aff. at P 35.

adds that Filing Parties provide no evidence that the planning criteria for local and regional facilities differ.

371. Several protestors contend that the proposed usage charge would unfairly impact high load-factor customers and benefit low load-factor ones. They explain that moving from a demand-based to a usage-based allocation method would impose higher costs on those customers that are more efficient users of the system (i.e., high load-factor customers) and, conversely, lower costs on those customers that are less efficient users of the system (i.e., low load-factor customers).[430] ABATE asserts that, rather than using energy consumption, the total peak demand placed on new transmission facilities is used to determine their capabilities, and as a result, energy consumption should not be the basis of the corresponding allocation methodology. Industrial Customers argue that the proposal would harm higher load-factor customers. Illinois Commission argues that demand charges create better incentives because, if a load-serving entity's peak demand increase, so would a demand-based MVP charge.

372. Wisconsin Industrials claim that the proposal would send a faulty price signal by benefiting customers with low load factors, which require greater amounts of load following services, rather than high load-factor customers, which have stable load profiles and use the system efficiently, thereby imposing fewer costs on the system. Wisconsin Industrials argue that the proposed usage charge risks driving out energy-intensive customers, with remaining low load-factor customers and wind intermittency causing system reliability issues and higher costs than before.

373. ITC Companies-Wolverine argue that, according to Dr. Tierney, the proposed usage charge may cause distortions in renewable energy export transactions and lead to inefficiencies in the energy market.[431] Dr. Tierney explains that Midwest ISO generators would need to structure their offers in neighboring regions to reflect the MVP usage charge, which could cause them to be dispatched out of economic merit order. She adds that the proposed usage charge would lead to higher charges for customers with high load factors.[432] They also assert that the proposed usage rate is more complicated than a demand charge and would require changes to the settlement process in place for other transmission facilities.

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[430] *See*, *e.g.*, Industrial Customers Comments at 42 (citing Industrial Customers Comments, Dauphinais Aff. at P 25-35).

[431] ITC Companies-Wolverine Comments at 15 (citing ITC Companies-Wolverine Comments, Tierney Aff. at 19).

[432] *Id.*, Tierney Aff. at 19.

374. Basin argues that the proposed usage charge on exports would allow customers to pay for reserved transmission capacity only when customers use it. Basin explains that firm point-to-point customers have the right to use their reserved transmission capacity at any time during the reservation term. Basin claims that it would be unjust and unreasonable to allow such customers to avoid paying for the entirety of that reserved capacity. Basin contends that, for example, the proposed usage charge would allow a customer to reserve firm point-to-point transmission capacity for an entire month and avoid paying any associated MVP charges if it does not actually transmit energy during the month. Basin argues that, in this example, Midwest ISO would either not recover its projected revenues for the MVP facilities or would shift the customers' costs to other transmission customers that cannot use the reserved capacity on a firm basis and that either alternative is unjust and unreasonable.

375. AF&PA, Illinois Commission, and MICH-CARE maintain that the proposed usage charge would be detrimental to demand response efforts. AF&PA argues that the proposed usage charge would discourage otherwise economical demand response options and skew decisions to favor the adoption of energy efficiency measures toward reductions during off-peak periods, which are easier to accomplish than during on-peak periods, by giving both types of reductions equal compensation under the proposal. Illinois Commission states that, under the proposal, a load-serving entity that increases its demand would pay the same amount as a load-serving entity that reduces its demand, assuming that their load only shifted and total consumption stayed the same. Illinois Commission argues that the Commission should reject the proposed usage rate in favor of a per-megawatt, peak demand approach. It notes that reducing peak demand could defer the need for transmission and generation investments and mitigate market power concerns and price volatility. MICH-CARE states that, when transmission costs are assigned on a megawatt basis, load-serving entities have an incentive to reduce megawatt loads using measures such as demand-side management programs. MICH-CARE contends that switching to a usage charge could eliminate these incentives, so that transmission and generation investments would supplant cheaper demand-side management programs and increase the production of negative externalities, such as carbon dioxide emissions.

376. Basin, Illinois Commission, Industrial Customers, and Steel Producers express concern regarding the application of the proposed usage charge to projects that provide reliability benefits. Industrial Customers argue that it is inappropriate to recover the costs of MVPs under Criterion 3 using a usage charge because reliability upgrades are generally driven by system peak demand, rather than energy usage. They claim that the costs of transmission upgrades undertaken to address reliability issues should be based on monthly coincident peak demand for network transmission customers and reserved capacity for point-to-point transmission customers. Basin asserts that Filing Parties' argument conflicts with MVP Criterion 3, which qualifies projects that address North American Electric Reliability Corporation or Regional Entity reliability standards,

because those standards evaluate the reliability of the system during contingencies at various load conditions. Steel Producers claim that, while MVPs may have reliability benefits, those reliability requirements are usually measured and set based on forecasted peak demand, and thus, the costs should be allocated on a demand basis.

377. Illinois Commission contends that a usage charge would be inappropriate for Baseline Reliability Projects because such projects are targeted at ensuring reliability, which is a capacity concept rather than an energy one. It states that, while a Baseline Reliability Project's benefits may accrue to more loads and in different proportions than those loads that necessitate the project, those benefits are secondary to the primary cause of the transmission facility's construction. It concludes that entities that induce known and measureable flows that are the primary cause of Baseline Reliability Projects (e.g., expected transmission facility overload) should be allocated the costs of those projects.

378. In addition, Basin disagrees with Filing Parties' argument that the proposed usage charge is appropriate because MVPs may reduce production costs. Basin contends that no correlation exists between whether a new transmission facility reduces production costs and the types of charge imposed and that this argument would justify usage charges for any transmission facility that reduces transmission congestion. Basin asserts that MVPs would likely increase production costs, rather than reduce them, by transmitting energy from new renewable resources that generally have higher "all-in costs" per kilowatt hour than existing non-renewable generation sources.[433]

379. Finally, Basin disagrees with Filing Parties' argument that the proposed usage charge is justified because only a small amount of wind generation would occur during periods of peak demand. Basin contends that transmission upgrades for wind resources are more likely determined during peak wind periods, rather than peak load periods. Basin also claims that Filing Parties' argument is equally true for all generation types because the monthly peak demands occur in only 12 of the 8760 hours of the year, and therefore, their argument would justify determining all transmission service charges based on usage. Basin notes that virtually all transmission charges are based on demand, not usage, and thus, Filing Parties' argument is invalid.

380. CPV disagrees with Filing Parties' argument that the proposed export charge is needed to avoid free riders in neighboring regions. CPV claims that customers using the Midwest ISO transmission network to export power are already assessed point-to-point transmission charges, which ensure that they are allocated the costs of all network upgrades. CPV argues that the costs of MVPs can be incorporated into the revenue requirement underlying those point-to-point charges, as they are updated routinely to

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[433] Basin Comments at 8.

reflect each transmission zone's changing costs, and therefore, a separate MVP charge is unnecessary. CPV contends that the current rate design charges customers on the basis of reserved capacity, rather than usage, which ensure that dispatch decisions are unaffected by reservation charges. CPV maintains that the proposed usage charge for MVPs would affect customers' dispatch decisions because their transmission costs will depend on whether they export energy from Midwest ISO in lieu of other resources. CPV asserts that, as a result, lower-cost generation in Midwest ISO might not be dispatched whenever the difference between the variable production costs of the Midwest ISO resource and external resources is less than the MVP charge. CPV concludes that the Commission should reject the proposed usage charge and instead require Midwest ISO to adhere to its current export rate design.[434]

381. To avoid creating market distortions, Midwest Generators recommend that the Commission require Midwest ISO to adhere to its current export rate design, whereby transmission reservation charges are routinely updated to reflect the costs of all expansion facilities and where external beneficiaries will pay their allocation of MVP costs.

b. <u>Answers</u>

382. In their answer, Filing Parties disagree with protestors arguing that the MVP should be recovered using a demand charge. They argue that, while a demand charge is appropriate for the recovery of facilities primarily addressing *local* reliability issues (e.g., Baseline Reliability Projects), the proposed usage charge would be appropriate for MVPs primarily addressing *regional* issues that involve compliance with public policy requirements and the resulting provision of regional economic benefits within the Midwest ISO market. Filing Parties also contend that it is not appropriate to limit MVP cost recovery to peak demand periods because the benefits of such projects would accrue throughout all hours of the year, not just during peak demand periods. In support, they note that, in her testimony, Ms. Curran explains that "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."[435] Filing Parties add that the existence of another

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[434] To the extent that the Commission accepts the proposed charge at the Midwest ISO-PJM seam, CPV argues that the Commission should require a different rate treatment at Midwest ISO's non-PJM interfaces. CPV Comments at 9.

[435] Filing Parties October 18, 2010 Answer at 72 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 13).

potentially just and reasonable approach does not render their MVP proposal unjust and unreasonable because they are only required to show that the proposal is just and reasonable, not that it is the best.[436]

c. Commission Determination

383. We find the proposed MVP rate design to be just and reasonable, and accept the proposed usage charge. We agree with Filing Parties that a significant portion of MVP benefits will likely accrue during off-peak demand periods and, therefore, a usage-based cost allocation methodology is consistent with cost causation principles. As Ms. Curran explains, "the benefits of 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."[437] We are not persuaded that the specific benefits associated with MVPs would likely be concentrated during peak demand periods. MVPs will produce benefits by allowing load to satisfy documented energy policy mandates or laws (e.g., enabling an increased reliance on renewable resources) that are not necessarily associated with peak demand periods and by producing economic benefits (e.g., reducing production costs) that occur throughout the year. A proposed usage charge would more appropriately reflect MVP benefits by allowing costs to be allocated during all hours of the year. Moreover, rather than making an upfront allocation of costs based on an analysis of benefits and usage at a specific point in time (as would a demand charge), the proposed MVP rate design allocates costs based on usage over time.[438] This also allows an allocation of costs to load in a manner that reflects changes in MVP beneficiaries over time.

384. We understand that alternate cost allocation methodologies could allocate MVP costs in a manner that is consistent with the Commission's cost causation principles. However, we need not consider those alternate cost allocation methodologies here. Filing Parties must prove that the proposed rate is just and reasonable, not that it is the best

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[436] *Id.* at 71 (citing *Oxy USA*, 64 F.3d at 692; *Cities of Bethany*, 727 F.2d at 1136; *Cal. Indep. Sys. Operator Corp.*, 120 FERC ¶ 61,023, at P 45 and n.34 (2008) (July 6, 2007 Order), *aff'd sub nom. Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520 (D.C. Cir. 2010); *New England Power Co.*, Opinion No. 352, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd sub nom. Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (*Town of Norwood*).

[437] Filing Parties July 15, 2010 Filing, Curran Test. at 12-13.

[438] *Id.*, Curran Test. at 9-10.

rate,[439] and we find that Filing Parties have met that burden. Protestors do not demonstrate that Commission precedent prevents the use of a usage charge for the recovery of transmission costs, and we note that the Commission has accepted usage charges in other contexts.[440] Therefore, we will accept the proposed usage charge, notwithstanding the merits of alternative allocation methodologies such as a demand charge or a two-part rate design.

385. The proposed MVP usage charge assigns MVP costs to parties in a manner that is roughly commensurate with the benefits that they are expected to receive from MVPs, consistent with a beneficiaries-pay approach to cost allocation. While several of the factors discussed by commenters, including Midwest ISO's precise method of selecting or sizing projects utilizing measures of peak demand, could be relevant under alternative cost allocation methodologies that consider the incurrence of costs (e.g., requiring generators to pay), these considerations do not inform our understanding of the incurrence of benefits due to the MVP proposal, and as such, they are not relevant here. Instead, Filing Parties rightly assert that all load would benefit from MVPs, and it is appropriate that they be allocated the corresponding costs in proportion to their relative use of the transmission system. Furthermore, we disagree with protestors' contention that Midwest ISO's use of demand charges to recover other types of costs necessitates the use of a demand charge here. Our evaluation of the appropriateness of the proposed usage charge is limited to the MVP proposal, particularly with regard to the regional public policy and economic benefits associated with MVPs. We are not persuaded that the application of a usage charge with regard to MVPs will conflict with or otherwise undermine Midwest ISO's use of alternate rate designs in other contexts.

386. Unlike a penalty charge, which is designed to provide an incentive for market participants to perform in a certain manner, our consideration of the proposed MVP rate design is focused on whether it produces a rate that assigns costs in accordance with cost causation principles. While protestors argue that the Commission should consider whether the proposed rate also creates desirable incentives (e.g., incentives to increase demand response and customers' load factors), none of these arguments demonstrate that the proposed rate design is unjust and unreasonable. Further, we disagree that the proposed usage charge would unfairly impact high load-factor customers. Protestors do not explain how customers that merely hold reserved transmission capacity could benefit

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[439] *See, e.g.*, Opinion No. 352, 52 FERC at 61,336, *aff'd sub nom. Town of Norwood*, 962 F.2d 20 (requiring only that the Commission make a reasoned decision based upon substantial evidence in the record).

[440] *See, e.g.*, *New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,068, at P 101 (2008), *order on reh'g*, 126 FERC ¶ 61,320 (2009).

from MVPs without actually scheduling energy for delivery using a reservation. As such, delivered energy may be better than reserved transmission capacity at indicating the relative benefits of MVPs, which would justify allocating MVP costs to parties based on their use of transmission reservations (i.e., to those parties with relatively high load factors) in accordance with cost causation principles. Therefore, we also find Basin's argument that MVP costs should be assigned to customers with reserved capacity that do not schedule energy to be without merit.

387. We disagree with protestors arguing that a proposed usage rate is inappropriate for MVPs under Criterion 3. By definition, MVPs under Criterion 3 must create at least one type of regional economic benefit. Therefore all MVPs will create regional benefits, and therefore the associated costs may be appropriately recovered regionally through a usage rate.

388. Finally, Filing Parties explain that the MVP usage rate recovers the monthly revenue requirement for MVPs from monthly withdrawals, specifically Monthly Net Actual Energy Withdrawals (a new term defined in the proposed Tariff), exports, and wheel-through transactions. Pursuant to the proposed tariff, 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."[441] In her testimony in support of the MVP rate design, Filing Parties' witness states that the energy withdrawals of Demand Response Resources and Emergency Demand Response resources should be netted against their energy injections to avoid "charging [load-serving] [e]ntities for load not actually consumed."[442]

389. In light of the explanation provided by Filing Parties' witness, we are concerned that the proposed definition of "Monthly Net Actual Energy Withdrawal" may actually be inconsistent with the Filing Parties' rate design objective. As proposed, for Demand Response Resources and Emergency Demand Response resources, hourly average Metered volumes, which should already net energy withdrawals against energy injections, would again be netted against their hourly Actual Energy Injections, thereby possibly resulting in netting such injections twice. To address this concern, we will require Filing Parties to submit, in the compliance filing due within 60 days from the date

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[441] Filing Parties July 15, 2008 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, First Revised Sheet No. 217.

[442] *Id.*, Curran Test. at 38.

of this order, an explanation as to how the proposed Tariff language is consistent with the rate design objectives stated by Filing Parties, and why it does not result in double netting.

2. Financial Transmission Right and Auction Revenue Right Allocation

390. Midwest ISO witness Mr. Todd Ramey states that the current Financial Transmission Right and Auction Revenue Right allocation design is premised on the traditional notion that local transmission is built for local needs and, thus, the investor in the transmission is also the beneficiary. The MVP concept moves to a broader funding base for transmission projects that have regional benefit. As such, Midwest ISO believes that the Financial Transmission Right and Auction Revenue Right allocation processes need to be modified so that the benefits of the MVP transmission as determined through the Financial Transmission Right and Auction Revenue Right processes are similarly socialized.[443]

a. Comments and Answers

391. Several parties express concern that the proposal causes unresolved issues with Financial Transmission Rights and Auction Revenue Rights. Dominion argues that, according to Mr. Ramey, the proposed export charge could result in market distortions, including short-run dispatch and Financial Transmission Right impacts. Dominion also notes that the LECG Report identified potential adverse market and Financial Transmission Right impacts due to the proposed usage charge. Designated PJM Parties also contend that Filing Parties acknowledge that its MVP proposal creates an unresolved mismatch between cost allocation and Financial Transmission Right and Auction Revenue Right allocation processes. AEP also argues that Filing Parties have not accounted for how Financial Transmission Rights would be accounted for under the proposal.

392. AMP states that if the proposal is accepted without modification to the Financial Transmission Right and Auction Revenue Right allocation processes, customers will be obligated to bear the costs of MVPs without receiving corresponding benefit in the form of Financial Transmission Rights or Auction Revenue Rights; instead Financial Transmission Rights and Auction Revenue Rights would be allocated to a different set of customers. AMP states that this inequity would be particularly grievous in the case of entities serving load outside of Midwest ISO where a transmission owner withdraws. AMP notes that Midwest ISO does not propose any corrective action here but simply

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[443] *See id.*, Ramey Test. at 8.

states that a stakeholder process is underway to consider whether changes to the Financial Transmission Right and Auction Revenue Right allocation design may be necessary. AMP asks the Commission to require Midwest ISO to correct this deficiency.[444]

393. Midwest TDUs state that Mr. Ramey's testimony appears to suggest a decoupling of Midwest ISO's allocation of long-term rights from the specific long-term power supply arrangements made and planned by load-serving entities to meet their load-serving obligations. Midwest TDU's argue that moving way from the Congressionally-directed linkage between long-term rights and the long-term power supply arrangements of load-serving entities would ignore federal laws and be a giant step in the wrong direction. Rather than hollowing-out the linkage between transmission planning, planned load-serving entity power supply arrangements, and upgrades, state Midwest TDUs, the MVP proposal should strengthen those connections consistent with FPA section 217 (b)(4). In this regard, Midwest TDUs ask the Commission to clarify that the existing language of Criterion 1 should be interpreted to encompass FPA section 217(b)(4)'s directive for planning to meet the reasonable needs of load-serving entities and to enable them to secure long-term rights for their planned long-term power supply arrangements.[445]

394. Filing Parties answer that they will address any MVP-related Financial Transmission Right and Auction Revenue Right design issues in stakeholder consultations to be held within the next four months and that it is internally studying potential issues and approaches that can be presented to the stakeholders for consideration and discussion. Filing Parties state that to the extent that it is determined that the Tariff's Financial Transmission Right and Auction Revenue Right provisions need to be modified in connection with the MVP proposal, the Tariff revisions will be filed either in the first or second quarter of 2011. Filing Parties state that the concerns raised by parties do not warrant deferment of the Commission's action on the MVP proposal.[446]

b. <u>Commission Determination</u>

395. We agree that the existing Financial Transmission Right and Auction Revenue Right allocation processes may need to be modified to be consistent with the allocation of MVP costs being accepted here. At the same time, we note that the first MVP is not

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[444] AMP Comments at 15-17.

[445] Midwest TDUs Comments at 14-16.

[446] Filing Parties October 18, 2010 Answer at 77-78.

currently expected to be in-service prior to January 1, 2013 and, thus, would not affect Financial Transmission Right and Auction Revenue Right allocations prior to the 2012-13 allocation year. Accordingly, we require Midwest ISO to address in a compliance filing, no later than June 1, 2011, what changes to its allocation of congestion rights are necessary to reflect the allocation of MVP costs being accepted here. In that compliance filing, Midwest ISO should explain how its compliance filing produces just and reasonable and not unduly discriminatory results.

3. Application of MVP Usage Rate to Exports and Wheel-Through Transactions

396. In July 2002, the Commission accepted the choices of AEP, Commonwealth Edison Company and Commonwealth Edison Company of Indiana (collectively, ComEd), and DP&L to join PJM.[447] In so doing, the Commission found that those RTO choices would result in an elongated and highly irregular seam between Midwest ISO and PJM that would "island" portions of Midwest ISO (Wisconsin and Michigan) from the remainder of Midwest ISO and would divide highly interconnected transmission systems across which substantial trade takes place. The Commission found that, without mitigation, the seam would subject a large number of transactions in the region to continued rate pancaking, impeding the goals of Order No. 2000.[448] Therefore, as a condition of accepting those RTO choices, the Commission required parties in the region to address the problem of rate pancaking across the Midwest ISO-PJM seam and instituted a proceeding under section 206 of the FPA[449] to investigate the rates for service between the two RTOs and established trial-type hearing procedures.[450] Following the hearing and issuance of an initial decision,[451] the Commission found the pancaked rates

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[447] *Alliance Co.*, 100 FERC ¶ 61,137 (2002) (Alliance 2002 Order), *order on reh'g*, 103 FERC ¶ 61,274 (2003).

[448] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[449] 16 U.S.C. § 824e (2006).

[450] Alliance 2002 Order, 100 FERC ¶ 61,137.

[451] *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 63,049 (2003).

for service wheeled through or out of one RTO to serve load in the other RTO were unjust and unreasonable and directed the RTOs to eliminate them.[452]

397. As part of the elimination of the pancaked rates between Midwest ISO and PJM, the Commission also directed Midwest ISO and PJM, under section 206 of the FPA, to work with their transmission owning members to propose, consistent with the RTOs' existing Joint Operating Agreement,[453] a method to allocate between the RTOs the costs of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO (cross border facilities).[454] The Commission ultimately accepted proposals to include in the Joint Operating Agreement methods to allocate between the RTOs the cost of cross border facilities built for reliability purposes (reliability cross border projects)[455] and cross border facilities that provide economic benefits (economic cross border projects).[456]

398. As part of its MVP proposal, Filing Parties state that all external transactions sinking outside of Midwest ISO, including those sinking in PJM, will be subject to the proposed MVP usage rate.[457] Filing Parties argue that applying the MVP usage rate to external transactions is appropriate because MVP transmission projects benefit load both inside and outside of the Midwest ISO region. Regarding the assessment of the MVP usage rate on exports to PJM, Filing Parties argue that the Commission's orders eliminating rate pancaking do not preclude the proposed Schedule 26-A surcharge on exports to PJM load that use new MVP transmission facilities. Filing Parties claim that the prior Commission orders on this subject essentially address existing transmission facilities, and expressly require the development of different rules for allocating the cost

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[452] *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 FERC ¶ 61,105 (2003) (July 23, 2003 Order).

[453] Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc., And PJM Interconnection, L.L.C. (Joint Operating Agreement).

[454] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168, at P 60 (2004) (November 18, 2004 Order), *order on reh'g*, 131 FERC ¶ 61,174, at P 22 (2010) (May 21, 2010 Rehearing Order).

[455] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084 (2008).

[456] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,102 (2009) (November 3, 2009 Order).

[457] Filing Parties July 15, 2010 Filing, Curran Test. at 14.

of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO.[458] Additionally, Filing Parties explain that, consistent with existing Commission directives, Midwest ISO will *not* assess charges on exports from Midwest ISO to PJM to cover the cost of existing facilities or the cost of new facilities that are not classified as MVPs.[459]

a. Comments

i. Inter-Regional Benefits

399. Alliant, E.ON, Iowa Board, ITC Companies-Wolverine, NIPSCO, and Wisconsin Commission support the proposed MVP usage rate for wheel-through and export transactions.[460] In general, they assert that loads outside of the Midwest ISO footprint will benefit from MVPs, and, therefore, an export charge is appropriate so that external loads pay their share of the cost for system upgrades from which they derive a benefit. They assert that, without an export charge, the entire cost of MVPs would be borne by Midwest ISO loads even though external loads also benefit from those projects. In addition, NIPSCO claims that charging load outside of the Midwest ISO footprint for a share of the costs associated with MVPs is consistent with cost causation principles because the external load being assessed the export charge will presumptively have determined that the price of energy being acquired from resources within or through Midwest ISO is economically beneficial even with the additional export charge.

400. ITC Companies-Wolverine assert that Filing Parties' proposal is a serviceable interim mechanism until an interregional cost allocation is in place, such as the one the Commission has proposed in its Transmission NOPR.[461] Wisconsin Commission notes, however, that the Transmission NOPR suggests that an export charge may not be the

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[458] *Id.*, Transmittal Letter at 25, n.105 (citing November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60, May 21, 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 22).

[459] *Id.*, Transmittal Letter at 25.

[460] Alliant Comments at 11; E.ON Comments at 10; Iowa Board Comments at 4-5; NIPSCO Comments at 4; ITC Companies and Wolverine Comments at 17-18; Wisconsin Commission Comments at 11-13.

[461] ITC Companies-Wolverine Comments at 18.

Commission's preferred cost allocation method, and, if the export charge is not adopted, consideration must be given to an MVP charge that is applied to generators.[462]

401. AEP, Dominion, EPSA, Exelon, and Designated PJM Parties argue that Filing Parties have not provided enough support for the proposed MVP usage rate for wheel-through and export transactions.[463] In general, they assert that Filing Parties have not demonstrated that loads outside of Midwest ISO will benefit from MVPs to an extent sufficient to justify allocating external loads a portion of the MVP costs. They argue that Filing Parties have not provided a quantitative analysis that shows how and to what extent external load will benefit from MVPs and do not consider, for example, whether external loads can meet the assumed public policy requirements without MVPs. Exelon notes that Midwest ISO's Regional Generation Outlet Study did attempt to quantify regional benefits, but it asserts that this study did not consider whether interregional benefits accrued to PJM customers.

402. AEP, Designated PJM Parties, DP&L, Dominion, and Exelon assert that the proposed MVP export charge is overly broad because MVPs may include intra-regional, interregional, and potentially low-voltage transmission projects, but the charge does not distinguish between MVPs that provide only intra-regional benefits and MVPs that also provide inter-regional benefits.[464] They argue that, other than conclusory statements, Filing Parties provide no basis to find that all MVPs will have the same external cost causers and beneficiaries, and, therefore Filing Parties have not justified requiring all exports to uniformly contribute to every MVP. DP&L argues, for example, that, if Baseline Reliability Projects meet the proposed MVP criteria, the associated costs will be exported outside of Midwest ISO, even though the projects are being constructed primarily to meet the reliability problems of Midwest ISO members.

403. AEP, EPSA and Exelon contend Midwest ISO has not explained how its proposal is consistent with sections 9.3 and 9.4 of the Joint Operating Agreement, which outlines how Midwest ISO and PJM will allocate costs of cross border facilities.[465] In addition,

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[462] Wisconsin Commission Comments at 12.

[463] AEP Comments at 6-7; Dominion Comments at 4-6; EPSA Comments at 5-12; Exelon Comments at 21-26; Designated PJM Parties Comments at 7-10.

[464] AEP Comments at 5-6; Designated PJM Parties Comments at 14; DP&L Comments at 3; Dominion Comments at 4-6; Exelon Comments at 25-26.

[465] AEP Comments at 7; AMP Comments at 6; CPV Comments at 4-10; EPSA Comments at 6-7; Exelon Comments at 16-19; Designated PJM Parties Comments at 16; FirstEnergy Comments at 41-43; Integrys Comments at 14-16; Joint Protestors

(continued…)

AEP states that under the Joint Operating Agreement, Midwest ISO and PJM share reciprocal rights on certain of each other's flowgates but notes that the MVP proposal does not include any reciprocal arrangements. Similarly, Designated PJM Parties argue that the proposed MVP export charge is discriminatory or preferential because non-Midwest ISO transmission providers do not assess reciprocal charges for exports from the non-Midwest ISO systems that are imported into Midwest ISO. They also argue that Filing Parties misapply the proposed MVP cost allocation by not considering entities more distant from Midwest ISO's borders.

ii. Rate Pancaking

404. AEP, AMP, CPV, EPSA, Exelon, Designated PJM Parties, FirstEnergy, Integrys, Joint Protestors, and Tenaska request that the Commission reject the proposal to assess the MVP usage rate on exports from Midwest ISO to PJM.[466] They contend that charging the MVP usage rate on exports to PJM would reinstitute rate pancaking between Midwest ISO and PJM, which violates prior Commission orders. They state that the Commission has previously found that pancaked rates between Midwest ISO and PJM are unjust and unreasonable and, therefore, ordered their elimination.[467] Accordingly, they argue that charging the MVP usage rate for exports to PJM violates Commission precedent and that arguments in support of charging MVP usage rate for exports are an impermissible collateral attack on prior Commission orders. In addition, Designated PJM Parties, Exelon, FirstEnergy, Integrys, and Joint Protestors state that there is no logical basis for the argument that the Commission's prohibition of rate pancaking between Midwest ISO and PJM applies only to the recovery of costs for existing facilities. Midwest Generators state that, although the Commission required Midwest ISO and PJM to develop a proposal for allocating between them the cost of cross border facilities, they contend that the Commission did not intend such proposal to include the resumption of rate pancaking.[468]

Comments at 21-26; Tenaska Comments at 4.

[466] *See*, *e.g.*, Exelon Comments at 16-17; CPV Comments at 8; Integrys Comments at 15 (citing, *e.g.*, July 23, 2003 Order, 104 FERC ¶ 61,105 at P 39).

[467] Midwest Generators Comments at 23 (citing, *e.g.*, November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60).

[468] *See*, *e.g.*, Joint Protestors Comments at 10-19; CPV Comments at 7-8; EPSA Comments at 7-11.

iii. Market Distortions and Seams Issues

405. AEP, CPV, Designated PJM Parties, Dominion, EPSA, Exelon, Joint Protestors, Midwest Generators, PJM, and Southwestern argue that assessing the MVP usage rate on exports and wheel-through transactions will cause market distortions. Several parties note that the LECG Report, as well as subsequent analysis by the Independent Market Monitor,[469] found that the application of the MVP usage rate to exports and wheel-through transactions would cause lower-cost Midwest ISO generators to become more expensive for external load customers, causing higher-cost generation from within the external areas to be used instead. This would put Midwest ISO generators at a disadvantage, they argue, and would also lead to a decrease interregional trading. In addition, EPSA and Joint Protestors contend that the proposed export charge does not allow investors to recognize the total costs of citing decisions because it does not directly allocate the costs of new transmission.

406. Designated PJM Parties, Exelon and PJM[470] also contend that the proposed MVP export charge would cause the same market distortions that the Commission relied upon as a key basis for eliminating pancaked rates between Midwest ISO and PJM.[471] They argue, therefore, that the proposal is a departure from this precedent and the Commission would need to justify such departure in order to approve the proposal. Designated PJM Parties state that Filing Parties assert without support that there are countervailing benefits that outweigh the identified market problems, but they argue that it is nearly impossible for the Commission to assess the extent to which the proposal could create market distortions, given the sparse record in this proceeding.

407. CPV, EPSA, Joint Protestors, and Midwest Generators also contend that, if approved, the proposed MVP export charge could cause other ISOs and RTOs to adopt similar charges.[472] They state that the Independent Market Monitor found that because

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[469] *See*, *e.g.*, Joint Protestors Comments at 15 (citing *Summary of IMM Comments on Cost Allocation Proposal* (Jun. 10, 2010) (Independent Market Monitor Comments), *available at* http://www.midwestiso.org/publish/Document/345da0_1299503ccb2_-7f5f0a48324a?rev=1).

[470] *See*, *e.g.*, Exelon Comments at 20; PJM Comments at 10-12.

[471] *See*, *e.g.*, PJM Comments at 11 (citing July 23, 2003 Order, 104 FERC ¶ 61,105 at P 28).

[472] CPV Comments at 7-8; EPSA Comments at 8; Joint Protestors Comments at 15; Midwest Generators Comments at 23.

Midwest ISO is a net importer of energy from most areas, end-use customers in Midwest ISO would be harmed far more by neighboring ISOs and RTOs levying an export charge on them than they would benefit from the revenues associated with the proposed export charge.[473] They state that the Independent Market Monitor similarly concluded that the proposed charge would serve as a barrier to full arbitrage between neighboring markets, create inefficiencies in the short-term dispatch of Midwest ISO and its neighbors, and invite neighboring systems to impose similar charges on energy imported into Midwest ISO. EPSA asserts that the seam created by the proposal would deepen if other ISOs and RTOs follow suit, which would be contrary to the Commission's policy of eliminating seams between markets.

408. Joint Protestors argue that the proposal improperly allocates MVP costs to existing customers that entered into long-term transmission agreements based on the knowledge of the costs associated with any transmission upgrades needed to grant the service and, thus, that do not benefit from the MVPs.[474]

iv. Inter-Regional Coordination

409. AEP, Designated PJM Parties, EPSA, Exelon, FirstEnergy, Integrys, and PJM argue that the proposal to assess the MVP usage rate on wheel-through and export transactions either has not been shown to be consistent with or is inconsistent with the Midwest ISO-PJM Joint Operating Agreement.[475] They state that the proposal is an attempt to circumvent the Joint Operating Agreement, which already provides for coordinated system planning between Midwest ISO and PJM, including a determination of which projects qualify for cross-border cost allocation.[476] PJM adds that Filing Parties have not clarified the relationship between the cost allocation for projects under the Joint Operating Agreement versus their proposal, including which cost allocation prevails in the event that a project meets the thresholds for cost sharing under both the MVP proposal and the Joint Operating Agreement. Exelon states that, absent revisions to the

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[473] *See, e.g.*, EPSA Comments at 9 (citing Independent Market Monitor Comments at 2; LECG Report at 24).

[474] Joint Protestors Comments at 12-13.

[475] AEP Comments at 4-5; Designated PJM Parties Comments at 13-14; EPSA Comments at 12-13; Exelon Comments at 21-26; FirstEnergy Comments at 43-44; Integrys Comments at 16; PJM Comments at 4-5.

[476] *See, e.g.*, AEP Comments at 5 (citing Joint Operating Agreement at sections 9.3-9.4).

Midwest ISO-PJM Joint Operating Agreement, the proposal violates the existing agreement (and, therefore, the Midwest ISO Tariff).

410. Several parties note that Filing Parties have not sought participation from PJM or other RTOs in connection with the development of the process for imposing MVP costs on exports. Exelon argues that, because several of the MVP starter projects are likely to significantly impact the PJM system, Midwest ISO should coordinate with PJM to ensure that they will not cause reliability violations or uneconomic congestion in PJM.

411. Joint Protestors contend that Midwest ISO and PJM should negotiate a cost sharing agreement applicable to load located in states that have enacted renewable portfolio standards.[477] They state that such an agreement would remove the need for the proposed export charge. They maintain that, in instances where a state has taken on the financial burden of self-supplying its own renewable portfolio, load should receive a dollar-for-dollar credit recognizing those costs that would have otherwise been cost shared on a regionalized basis between Midwest ISO and PJM. Joint Protestors add that such an agreement could also address the limitations of the transmission system.[478]

v. OASIS and After-the-Fact Charges

412. EPSA, Joint Protestors, and Midwest Generators contend that the proposed *ex post* rate calculation for the MVP usage rate does not comply with the requirement that transmission providers post on their Open-Access Same-Time Information System (OASIS), on a timely and transparent basis, transmission service prices and associated terms and conditions.[479] They note that under the proposed MVP usage rate, the billing determinants will not be known until after the month's business has closed and, therefore, the MVP usage rate cannot be determined before a customer takes service. EPSA argues that preventing customers from knowing the applicable export charges until potentially a full month after an export occurs is contrary to Commission policy and the public interest.

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[477] Joint Protestors Comments at 20.

[478] Joint Protestors note, for example, that the Michigan Thumb will have limited transfer capability to the other Midwest ISO members after the withdrawal of FirstEnergy in 2011 and that some state renewable portfolio standards must be satisfied with in-state resources. They contend that the agreement could ensure that the associated costs are not simply socialized to all load.

[479] EPSA Comments at 11-12; Joint Protestors Comments at 27-28; Midwest Generators Comments at 21-22.

413. CPV and Midwest Generators contend that assessing the proposed MVP export charge after the fact will cause market distortions for exports because transmission customers will be forced to make dispatch decisions based on their best guess of what after-the-fact MVP charges will be.[480] They state that the proposal does not have similar effects on the dispatch decisions of customers internal to Midwest ISO because load will pay the usage charge regardless of whether they rely on internal or external resources. They add that the after-the-fact posting of prices also disproportionately affects customers that commit to long-term contracts because, over time, customers will have the incentive to rely less on exports and, therefore, the MVP costs will be allocated over fewer MWh.[481]

414. Midwest Generators and CPV disagree with Filing Parties' argument that the proposed export charge is needed to avoid free riders in neighboring regions.[482] They argue that customers using the Midwest ISO transmission network to export power are already assessed point-to-point transmission charges, which ensures that they are allocated the costs of all network upgrades. They argue that the costs of MVPs can be incorporated into the revenue requirement underlying those point-to-point charges, as they are updated routinely to reflect each transmission zone's changing costs, and therefore, a separate MVP charge is unnecessary. Dominion counters that the proposal would actually force non-riders to pay, in violation of the Commission's cost causation principles.

415. Joint Protestors argue that, if the Commission finds that assessing the MVP usage rate on exports and wheel-through transactions is acceptable, Midwest ISO has to propose a rate calculation that will provide market participants with advance notice of the cost of transmission service.[483] Absent a cost sharing agreement between Midwest ISO and PJM, Joint Protestors propose that, in calculating the rates for exports and wheel-through transmission service, the MVP annual revenue requirements should be added to the numerator used in calculating the maximum rates for the current schedule 7 (Firm) and schedule 8 (Non-Firm) Point-To-Point Transmission Service system-wide rate with the transmission owner's current revenue requirements for the existing transmission

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[480] CPV Comments at 7; Midwest Generators Comments at 22-23.

[481] Midwest Generators Comments at 22. Midwest Generators also contend that the design of the proposed usage charge conflicts with the Commission's requirements for the development of unit charges for firm transmission services. *See id.* at 21.

[482] *Id.* at 20-21; CPV Comments at 5.

[483] Joint Protestors Comments at 28.

facilities. They contend that this methodology would ensure that the rate is posted in advance, consistent with OASIS requirements, but that the MVP annual revenue requirement would be collected on an after-the-fact basis, consistent with the proposal. They maintain that the total revenue requirements would also be collected based on a transmission customer's reserved capacity. Joint Protestors claim that the charge should be based on reserve capacity, regardless of whether the customer actually schedules energy on a given path.

b. Answers

i. Inter-Regional Benefits

416. In response to comments regarding the benefits MVPs provide to external loads, Filing Parties state that major, integrated facilities, such as MVPs, support all uses of the system, including transmission on the system for delivery to another system. They claim that MVPs that solve reliability issues on the Midwest ISO transmission system do so for all users of the system, regardless of where their ultimate loads are located. They maintain that MVPs that reduce congestion and enhance market efficiency do so for any transmission customers, whether their withdrawal point is inside of the Midwest ISO region or at an interface with an adjacent system. Filing Parties also argue that allocating MVP costs to external loads is consistent with the Commission's repeated findings, upheld by the courts, that the Midwest ISO markets "produce global benefits to those transacting over the Midwest ISO grid" including "a more reliable and efficiently-used transmission grid," "clear price signals for better infrastructure siting," and "price transparency, which benefits even bilateral contract formation."[484] Filing Parties state that exempting grid users whose withdrawal points happen to be at interface points and to assess the associated costs on every other withdrawal point on the system would be unduly discriminatory.

417. Filing Parties argue that the Commission routinely approves export charges for Midwest ISO and numerous other RTOs and that it is a well-accepted rate practice. They note that Midwest ISO assesses charges for export transactions (except at the PJM interface), as does PJM, SPP, New York Independent System Operator, Independent System Operator-New England, and California Independent System Operator. Filing

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[484] Filing Parties October 18, 2010 Answer at 48 (citing *Transmission Owners of the Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,339, at P 33, *order on reh'g*, 113 FERC ¶ 61,122 (2005), *aff'd sub nom. E. Kentucky Power Coop., Inc. v. FERC*, 489 F.3d 1299 (D.C. Cir. 2007) (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,235, at P 43, *order on reh'g*, 109 FERC ¶ 61,157 (2004)); *Midwest ISO Transmission Owners*, 373 F.3d at 1369-71).

Parties further assert that, as a general matter, requiring parties to pay for the use of major integrated facilities in a transmission system when they use that system to move power to another transmission provider is just and reasonable. They state that, in Order No. 888, the Commission found that network customers cannot use their network entitlement to make off-system sales and must instead take and pay for point-to-point transmission for that service.[485] They also note that, in Order No. 890, the Commission held that network customers must pay unreserved use penalties if they use their network service to make off-system sales.[486]

418. Filing Parties disagree with commenters that fault the MVP proposal for not including a procedure for PJM to assess on Midwest ISO load a share of the costs associated with PJM transmission expansions that are comparable to MVPs. Filing Parties contend that they are not responsible for making any such filing. They state that the responsibility would instead rest with the public utilities, including the RTO, that would own or operate such facilities.

419. MidAmerican opposes the requests to reduce or eliminate the MVP usage charge applicable to export and wheel-through transactions, arguing that MVPs would benefit external load. It contends that both transaction types would utilize the capacity provided by MVPs because export transactions originate from within and wheel-through transactions pass through the Midwest ISO footprint. MidAmerican also maintains that MVPs would benefit external loads subject to public policy requirements. It adds that, to the extent that external loads purchase energy from resources within Midwest ISO or through the Midwest ISO region, the price of the energy being acquired must be economically beneficial. MidAmerican concludes that allocating MVP costs to external loads would be consistent with the cost-causer and beneficiary-pay principles.

420. In response to Filing Parties' answer, Designated PJM Parties argue that Filing Parties incorrectly presume that all MVPs would benefit external load in the same manner and relative magnitude, no matter where they are located, how they are configured, when they are installed, how they may be loaded or constrained, or how they related to facilities being installed in areas outside of Midwest ISO. Designated PJM Parties submit that Filing Parties' answer confirms that they have no evidentiary support for this assertion. Designated PJM Parties also argue that all of the supportive comments reflect the "unremarkable and unsurprising parochial view" of Midwest ISO participants

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[485] *Id.* at 43 (citing Order No. 888, FERC Stats. & Regs. at 31,751).

[486] *Id.* (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 842).

that they would fare better if loads outside of Midwest ISO share in their transmission upgrade costs.[487]

421. Designated PJM Parties argue that Filing Parties' reference to previously-accepted export charges does not support allocating MVP costs to load in PJM. They state that Filing Parties' statement that "Midwest ISO assesses charges for export transactions (except for PJM interfaces as noted above)" effectively concedes that export charges were unambiguously rejected for transactions between Midwest ISO and PJM.[488] In addition, they argue that Filing Parties cannot reconcile their unilateral attempt to foist charges for internal facility upgrades on external parties with the principles reflected in the Midwest ISO-PJM Joint Operating Agreement or with the Commission's pending Transmission NOPR.[489]

422. Dominion claims that Filing Parties' answer mischaracterizes Dominion's position regarding the MVP proposal.[490] Dominion clarifies that it believes that the proposed MVP rate fails in two respects: first, the rate does not distinguish between MVPs that provide only intra-regional benefits and MVPs that provide both intra- and inter-regional benefits; and, second, the rate would apply to PJM customers for MVPs that would not provide inter-regional benefits. Dominion contends that accepting the proposal's potential market distortions and foisting MVP costs on non-beneficiaries would be an unreasonable solution to an alleged free-rider problem and would violate cost causation principles. Dominion further clarifies that only the subset of MVPs shown to benefit PJM should be allocated to PJM load.

ii. Rate Pancaking

423. Filing Parties argue that the Commission's orders eliminating rate pancaking between Midwest ISO and PJM do not prohibit its proposal to assess the MVP usage rate

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[487] *Id.*

[488] Designated PJM Parties November 2, 1010 Answer at 6 (citing Filing Parties October 18, 2010 Answer at 42).

[489] *Id.* (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 164).

[490] Dominion states that Filing Parties incorrectly include Dominion among commenters alleging that MVP benefits stop at the Midwest ISO-PJM seam and objecting to the recovery of any MVP costs from Midwest ISO transmission customers that serve load outside of Midwest ISO. Dominion November 5, 2010 Answer at 2 (citing Filing Parties October 18, 2010 Answer at 42, 47).

on exports and wheel-through transactions. Filing Parties contend that the Commission's previous orders expressly encourage the broader sharing of the costs of new transmission facilities resulting from the RTO's regional planning process.[491] They also assert that in its previous orders, the Commission addressed whether to require PJM loads to share in the costs of all Midwest ISO transmission, including projects planned by individual transmission owners to meet their local needs, which is distinct from the MVP cost allocation that applies only to new projects that provide broad benefits. Filing Parties state that the MVP proposal does not exempt from MVP charges deliveries to Midwest ISO's interface with PJM because such withdrawals contribute to MVP costs, just like all other withdrawals anywhere else on the Midwest ISO transmission system. They state that, consistent with prior Commission orders, however, rates covering the costs of existing and new (non-MVP) transmission facilities for external transactions sinking in PJM would continue to be discounted to zero.

424. Filing Parties argue that applying the Commission's findings in the orders that eliminated rate pancaking between Midwest ISO and PJM to the MVP proposal ignores the significantly changed circumstances since those orders were issued. They contend that the Commission's directives were based on a perceived irregular seam between Midwest ISO and PJM, which they claim, has since been largely eliminated,[492] and the Commission's expectations of a joint and common energy market between Midwest ISO and PJM, which has not emerged. They argue that the circumstances that warranted an exception to the general rule that allows transmission charges for inter-RTO transactions have materially changed and thus would not support a new extension of that exception to exempt Midwest ISO transmission customers that serve PJM loads from bearing any share of MVP costs.[493]

425. Filing Parties argue that commenters ignore the fact that multiple Midwest ISO charges are assessed on transmission customers serving external load. They note that Schedules 10 and 17 of the Midwest ISO Tariff recover the costs of, among other things,

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[491] Filing Parties October 18, 2010 Answer at 44 (citing November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60, May 21, 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 22).

[492] Filing Parties submit that, since those orders were issued, Illinois Power decided to remain in Midwest ISO, rather than forming a virtual PJM island surrounded by Midwest ISO transmission owners, and American Transmission System, Inc., which forms an extended Midwest ISO northeastern seam between PJM and Canada, had obtained Commission approval to transfer from Midwest ISO to PJM.

[493] Filing Parties October 18, 2010 Answer at 45.

expansion planning and administering the energy and ancillary services markets from all transmission customers.[494] Filing Parties state that, in the orders approving those schedules, the Commission found it appropriate to impose charges on all transactions on

the Midwest ISO transmission system.[495] Filing Parties conclude that MVP benefits are comparable to the regional benefits provided by Midwest ISO itself and, thus, are properly charged to all transmission customers.

426. Filing Parties argue that the MVP proposal is consistent with the Commission's approach of treating Midwest ISO and PJM loads comparably. They state that the Commission has recognized that "all customers have access to the transmission system of the entire [Midwest ISO and PJM] region and can transact freely over that system without paying transactions through-and-out charges," thereby enabling a broad distribution of benefits and making more transactions economic across the Midwest ISO-PJM region.[496] Filing Parties claim that the lack of point-to-point transmission charges between Midwest ISO and PJM shows that PJM loads are even more comparable to Midwest ISO loads, and the MVP proposal treats loads in Midwest ISO and PJM equally for purposes of recovering the costs of new, broadly beneficial transmission projects.

427. In response, Designated PJM Parties argue that Filing Parties mischaracterize the Commission's previous orders that prohibited rate pancaking between Midwest ISO and PJM. Designated PJM Parties claim that, contrary to their initial proposal, Filing Parties concede in their answer that the Commission's prohibition against rate pancaking applies to both existing and new transmission facilities (rather than only to existing ones).[497] Designated PJM Parties maintain that Filing Parties fail to explain why or where the Commission exempted new MVP-type facilities, arguing that the Commission did not carve out MVP or other types of facilities from its prohibition against rate pancaking. Designated PJM Parties also assert that the Commission's directive that the RTOs and

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[494] *Id.* at 45-46 (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Schedule 10, section II; *id.* Schedule 17, section II.A).

[495] *Id.* at 46 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,051, at P 24 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,038, at 61,163 (2003); *Midwest ISO Transmission Owners*, 373 F.3d at 1370).

[496] *Id.* (citing May 21, 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85).

[497] Designated PJM Parties November 2, 2010 Answer at 5 (citing Filing Parties July 15, 2010 Filing, Transmittal Letter at 25, n.105; Filing Parties October 18, 2010 Answer at 41).

their transmission owners develop and file a proposal for allocating the costs of new transmission facilities with cross-border benefits did not permit or encourage pancaked rates.

428. Designated PJM Parties argue that Filing Parties' suggestion that the Commission's previous orders eliminating rate pancaking across the Midwest ISO-PJM seam are no longer relevant constitutes a collateral attack on those orders. Designated PJM Parties argue that Filing Parties cannot ignore the Commission's precedent by arguing that circumstances have materially changed via a unilateral filing under section 205 of the FPA. They contend that, at a minimum, Filing Parties carry the burden of establishing that the Commission's existing ratemaking rules are unjust and unreasonable under section 206 of the FPA, and Filing Parties have made no such showing. Designated PJM Parties maintains that the Commission has rejected complaints that were integral parts of similar pleadings because such procedure would provide inadequate notice of the compliance.[498] They also note that the Commission has consistently rejected attempts to attack or evade previous Commission directives in other incidental proceedings.[499] They conclude that the Commission's prohibition of rate pancaking is effective until changed due to findings in a properly-initiated section 206 proceeding.

429. Designated PJM Parties argue that schedules 10 and 17 of the Midwest ISO Tariff fail to support the proposed MVP charges. They explain that schedules 10 and 17 recover Midwest ISO's expenses and have nothing to do with the cost of transmission owners' facilities or the transmission services that they enable. Therefore, they conclude that schedules 10 and 17 provide no support for overriding the Commission's prohibition of transaction-based transmission service charges across the Midwest ISO-PJM seam. They add that schedule 26 explicitly eliminates network upgrade charges on export transactions to PJM, consistent with the Commission's orders.[500]

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[498] *Id.* at 7 (citing *Louisville Power & Light Co.*, 50 FERC ¶ 61,040, at 61,062-63 (1990); *Indiana Michigan Power Co.*, 51 FERC ¶ 61,191, at 61,524 (1990); *Virginia Electric Power Co.*, 53 FERC ¶ 61,047, at 61,167 (1990)).

[499] *Id.* (citing *Pacific Gas and Elec. Co. v. Delta Energy Ctr., LLC*, 116 FERC ¶ 61,004, at P 36 (2006), *reh'g denied*, 116 FERC ¶ 61,207 (2006); *Californians for Renewable Energy, Inc. v. Calpine Energy Servs., L.P.*, 106 FERC ¶ 61,055, at P 10 (2004), *reh'g denied*, 107 FERC ¶ 61,238 (2004); *Dynegy Power Mktg., Inc.*, 101 FERC ¶ 61,369, at P 18 (2002); *El Segundo Power, LLC*, 91 FERC ¶ 61,110, at 61,390-91, *reh'g denied*, 95 FERC ¶ 61,159 (2001)).

[500] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194 (2005) (conditionally accepting cross-border cost allocation for reliability transmission

(continued…)

iii. Market Distortions and Seams Issues

430. In response to commenters' allegations regarding potential adverse market impacts, Filing Parties contend that Midwest ISO commissioned the LECG Report to assess the possible market impacts from various cost allocation approaches. Filing Parties maintain that the LECG Report identified possible impacts from any MVP cost recovery approach, which reflects that rate design "is a matter of judgment, rather than a matter for the slide rule."[501] While Filing Parties concede that the LECG Report concluded that there could be some market impacts from an export charge, they assert that the LECG Report concluded that those impacts could be overcome by spreading the costs among all beneficiaries of MVPs to place external loads in a position comparable to Midwest ISO load. According to Filing Parties, the LECG Report indicated that, otherwise, external loads would enjoy an undue advantage by benefitting from the transmission constructed to support MVPs without having any cost responsibility. Filing Parties state that the LECG Report found that no major problems have resulted from existing Midwest ISO and PJM export charges not scheduled in the day-ahead market. They also submit that the LECG Report stated that export charges can help to avoid disincentives for participation in Midwest ISO markets if load-serving entities could, by withdrawing from Midwest ISO, avoid all transmission investment costs while continuing to receive many of their benefits.[502]

431. In response, Designated PJM Parties contend that the Commission should reject Filing Parties' reliance on the LECG Report regarding the possible market impacts of the proposed export charge. Designated PJM Parties contend that, instead of studying the MVP proposal, the LECG Report studied a prior cost allocation method that would have recovered some MVP-related costs from imports as well as exports.[503] They add that the LECG Report contained a qualitative, rather than quantitative, discussion of possible impacts. Designated PJM Parties conclude that the report is unreliable and cannot be used to assess the extent to which market distortions would exist.

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projects); November 3, 2009 Order, 129 FERC ¶ 61,102 (accepting cross-border cost allocation for economic transmission projects).

[501] Filing Parties October 18, 2010 Answer at 53 (citing *Colorado Interstate Gas*, 324 U.S. at 589).

[502] *Id.* at 53-54 (citing Filing Parties July 15, 2010 Filing, Ramey Test. at 2-3; LECG Report at 40-41).

[503] *Id.* (citing Filing Parties July 15, 2010 Filing, Ramey Test. at 3, 7-8).

iv. Inter-Regional Coordination

432. In their answer, Filing Parties contend that the MVP proposal is not contrary to the Midwest ISO-PJM Joint Operating Agreement. They claim that, although either Midwest ISO or PJM may introduce other projects into Midwest ISO and PJM's coordinated regional planning process, the Joint Operating Agreement explicitly requires joint study only for facilities that respond to specific requests for generator interconnections or for transmission service.[504] Filing Parties contend that this joint study requirement would not apply to MVPs because the proposal specifically excludes Network Upgrades driven solely by interconnection service or transmission service requests.[505] They argue that the Joint Operating Agreement's Coordinated System Planning provisions do not purport to address cost allocation for other types of projects or for projects identified in each RTO's regional plans that provide other types of benefits. Filing Parties maintain that, in a previous proceeding, Midwest ISO and PJM jointly explained that projects designed primarily to allow renewable generation facilities to serve load pursuant to any renewable portfolio standards would likely not qualify as cross-border projects under the Joint Operating Agreement and that each RTO is free to proceed unilaterally with regard to projects that do not strictly meet the Joint Operating Agreement's project classification criteria but involve cross-border benefits.[506] Filing Parties claim that any cost sharing that may be warranted by such cross-border benefits would not be governed by the Joint Operating Agreement.

433. Filing Parties argue that proposed Criteria 1, 2, and 3 differ in several respects from reliability cross border projects and economic cross border projects under the Joint Operating Agreement. They state that several commenters recognize that the Joint Operating Agreement does not address public policy-driven projects under Criterion 1. Filing Parties submit that MVPs under Criterion 2 utilize different benefit measures and threshold benefits-to-cost ratios than economic cross border projects.[507] They also assert

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[504] Filing Parties October 18, 2010 Answer at 49-50 (citing Joint Operating Agreement, sections 9.3.3, 9.3.4).

[505] *Id.* at 50 (citing Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, section II.C.2(f)).

[506] *Id.* at 50-51 (citing Midwest ISO and PJM January 28, 2009 Filing, Docket No. ER05-6-108, *et al.*, at 6).

[507] Filing Parties state that Criterion 2 uses a minimum benefits-to-cost ratio of 1.0, whereas Cross-Border Market Efficiency Projects use 1.25 to 1.0. They add that the benefits measure for Cross Border Market Efficiency Projects is based on adjusted production cost and net load payments, whereas the measure for Criterion 2 considers the

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that MVPs under Criterion 3 address reliability needs and provide widespread economic benefits, while reliability cross border projects include facilities that address reliability needs. They add that the Joint Operating Agreement contains different thresholds for reliability cross border projects and reliability cross border projects than the proposed $20 million or five-percent thresholds for MVPs.[508]

434. Filing Parties maintain that whether the Joint Operating Agreement should be amended to address additional categories of projects would be a matter for future negotiations between the RTOs and their stakeholders. They conclude that nothing prevents the Commission from finding that the broad benefits of MVPs warrant recovering their costs from all grid users whether they serve on-system or off-system loads.

435. In response to Filing Parties' answer regarding the Joint Operating Agreement, Designated PJM Parties contend that Midwest ISO may not unilaterally invent its own cross-border cost allocation. Designated PJM Parties argue that the Commission explicitly required Midwest ISO and PJM to jointly propose the allocation of costs for transmission facilities that produce inter-regional benefits,[509] which resulted in the current Joint Operating Agreement. They argue that, as a result, Midwest ISO and PJM (and their affected transmission owners) must jointly propose the allocation of transmission projects that create inter-regional benefits through the Joint Operating Agreement. They maintain that the statements made in a transmittal letter by Midwest ISO and PJM, as cited by Filing Parties to support that inter-regional cost allocation proposals may be unilateral, are nonsensical, carry no weight, are not part of a filed tariff, and do not override prior Commission orders to the contrary. According to Designated PJM Parties, allowing Midwest ISO to unilaterally propose its own cross-border allocation would allow it to skirt the cost allocation process of the Joint Operating Agreement at anytime.

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reduction of production costs and the associated reduction of prices resulting from transmission congestion relief to be a single type of economic value (i.e., they are not additive). *Id.* at 51, n.152-153 (citing Joint Operating Agreement, section 9.4.3.1.2.1).

[508] *Id.* at 52 (citing Joint Operating Agreement, section 9.4.3.1 and 9.4.3.1.2).

[509] Designated PJM Parties November 2, 2010 Answer at 9 (citing November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60 ("we will require that the RTOs and their transmission owners develop and file within 180 days of the date of this order a proposal for allocating to the customers of each RTO the cost of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO")).

436. Designated PJM Parties contend that MVPs could easily qualify as cross-border projects under the Joint Operating Agreement. They state that the only difference between the proposed MVPs and other cross-border projects under the Joint Operating Agreement is that Filing Parties have proposed a unilateral ability to designate projects as MVPs. They conclude that the MVP proposal is contrary to the Joint Operating Agreement as the mandated vehicle for evaluating the impacts of cross-border projects.

v. OASIS and After-the-Fact Charges

437. Filing Parties submit that the proposed MVP charge does not violate OASIS posting requirements. They maintain that, while the proposed MVP charge recovers transmission revenue requirements, it is not a charge for transmission service. They assert that OASIS posting requirements apply to transmission service customers take pursuant to Schedules 7, 8, and 9 of the Midwest ISO Tariff but the proposed MVP usage charge under Schedule 26-A is merely added to the basic transmission service charge so that the OASIS posting requirements are inapplicable. To the extent that the Commission considers a waiver from the OASIS posting requirements necessary for the proposed MVP charge, however, Filing Parties so request such a waiver. They add that the Commission has granted such waivers in contexts where the posting requirements are deemed incompatible with the service being provided.[510]

438. While Filing Parties argue that the Commission should accept the proposed MVP rate, they state that one alternative to the proposed MVP charge would be a true-up rate that can be posted on OASIS. Filing Parties contend that a true-up rate is not necessarily a better approach, and even if it were, they are only required to submit a just and reasonable approach and are not required to propose the best approach.[511]

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[510] Filing Parties October 18, 2010 Answer at 73 (citing *New York Indep. Sys. Operator, Inc.*, 130 FERC ¶ 61,104, at P 18 (2010); *Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,260, at P 29-30 (2009)).

[511] *Id.* at 72-73 (citing July 6, 2007 Order, 120 FERC ¶ 61,023 at P 45 and n.34, *reh'g denied*, 124 FERC ¶ 61,094 (2008) ("For a proposal to be acceptable, it need not be perfect nor even the most desirable; it need only be reasonable"); Opinion No. 352, 52 FERC at 61,336; *Cities of Bethany*, 727 F.2d at 1136, *cert. denied*, 469 U.S. 917 (utility needs to establish that its proposed rate is reasonable, not that it is superior to alternatives)).

c. Commission Determination

439. We accept the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM. Major integrated facilities such as MVPs support all uses of the system, including transmission on the system that is ultimately used to deliver to an external load. Filing Parties have shown that the MVP proposal would enable projects to improve system reliability, reduce congestion, satisfy documented energy policy mandates or laws, and enhance market efficiency, which would benefit all users of the integrated transmission system, regardless of whether the ultimate point of delivery is to an internal or external load. The proposed criteria ensure that these broad, inter-regional benefits result from MVPs, as we discuss above. We also disagree that Criterion 1 MVPs benefit only Midwest ISO loads that are subject to documented energy policy mandates or laws because Criterion 1 MVPs improve the Midwest ISO transmission system and also permit external entities to use Midwest ISO generation to satisfy external energy policy mandates or laws. We also note that there is no involuntary assignment of costs here given that the MVP usage rate applies to export and wheel-through transactions (i.e., customers that are taking service from Midwest ISO), rather than an external entity taking no service or buying no energy from Midwest ISO, which would not be charged under this proposal).

440. However, we reject the proposed MVP charge for export and wheel-through transactions that sink in PJM. Filing Parties have not shown that their proposal - to assess the MVP usage rate on all exports and wheel-through transactions - does not constitute a resumption of rate pancaking along the Midwest ISO-PJM seam. Such rate pancaking is contrary to the Commission's previous orders eliminating rate pancaking between Midwest ISO and PJM. Specifically, the Commission found that, due to the RTO scope and configuration that resulted from the RTO choices of certain transmission owners now within Midwest ISO and PJM, the continuation of rate pancaking between PJM and Midwest ISO violated Order No. 2000's requirement that RTOs eliminate rate pancaking within a region of appropriate scope and configuration. Accordingly, the Commission found that such pancaked rates constituted unjust and unreasonable rates and required the RTOs to eliminate them.[512] While there have been some changes since the Commission eliminated rate pancaking between Midwest ISO and PJM, we do not find that such changes are sufficient to mitigate the RTO scope and configuration concerns that led the Commission to find that pancaked rates between Midwest ISO and PJM are unjust and unreasonable. Furthermore, to the extent that Filing Parties are arguing that the Commission's decision to eliminate rate pancaking is now incorrect,

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[512] *See*, *e.g.*, July 23, 2003 Order, 104 FERC ¶ 61,105 at P 35.

making such an argument in this section 205 filing represents an impermissible collateral attack on prior Commission orders.

441. Accordingly, the rate pancaking for transactions between Midwest ISO and PJM that would result from the proposal to charge the MVP usage rate on wheel-through and exports to PJM would conflict with Commission precedent.[513] We therefore reject Filing Parties' proposal as it relates to charges on wheel-through and export transactions to PJM. We require Filing Parties to submit, in the compliance filing due 60 days from the date of this order, tariff revisions to provide that wheel-through and export transactions to PJM are not subject to MVP charges.

442. In addition, while Filing Parties are correct that the Commission directed Midwest ISO, PJM, and their transmission owners to develop a proposal to allocate costs associated with transmission facilities that create cross border benefits, it did not allow them to re-impose the pancaked rates that the Commission had found unjust and unreasonable.[514] Further, Filing Parties have not demonstrated that Midwest ISO's administrative charges under Schedules 10 and 17 are comparable to the proposed MVP charges or that the Commission's approval of those charges would justify a resumption of rate pancaking along the Midwest ISO-PJM seam.

443. We disagree that the proposed MVP charge for export and wheel-through transactions should be rejected due to possible market distortions. While Filing Parties concede that the proposal has the potential to create negative market impacts, such impacts are difficult to predict in advance, and, in any event, there would likely be market distortions associated with any cost allocation methodology that parties propose. For this reason, it has long been recognized that rate design is "not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[515] Many of these market impacts could be overcome by spreading the costs among all beneficiaries of MVPs to place external loads in a position comparable to Midwest ISO load, which is precisely what the proposed charge for export and wheel-through transactions (other than those to PJM) would do. Absent the proposed MVP charge to exports and wheel-through transactions (other than those to PJM), external loads would enjoy an undue advantage by benefiting from the transmission constructed to support MVPs without having any cost responsibility, contrary to cost causation principles. The MVP proposal also avoids

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[513] *Id.*

[514] November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60.

[515] *Colorado Interstate Gas*, 324 U.S. at 589.

creating an undesirable incentive for load-serving entities to withdraw from Midwest ISO to avoid paying MVP costs while continuing to receive MVP benefits.[516]

444. Finally, we find that the MVP proposal does not violate the Commission's OASIS posting requirements. The Commission requires transmission providers to "post prices and a summary of the terms and conditions associated with all transmission products offered to transmission customers."[517] This OASIS posting requirement applies to transmission products, such as charges for transmission service under Schedules 7, 8, and 9 of the Midwest ISO Tariff. We find that the MVP proposal does not create a new transmission product, and we agree with Filing Parties that the proposed MVP charge merely recovers transmission revenue requirements.[518] However, we recognize protestors' concerns that advance notice of MVP charges would allow parties to make more sound business decisions, and we encourage Midwest ISO to continue working with its stakeholders to develop mechanisms to provide such advance notice.

4. No Cost Assignment to Grandfathered Agreements

445. Filing Parties state that MVP costs will not be assessed to grandfathered agreements under Schedule 26-A of the Tariff and that this treatment is similar to the treatment of grandfathered agreements under Schedule 26, which governs the recovery of the costs of network upgrades that are determined under Attachment FF to be subject to Attachment GG, the latter of which is used to calculate charges for Baseline Reliability Projects and Market Efficiency Projects.[519]

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[516] Filing Parties July 15, 2010 Filing, Ramey Test. at 2-3.

[517] 18 C.F.R. § 37.6(c)(1) (2010) (emphasis added).

[518] Therefore, Filing Parties' request for waiver of these requirements is moot.

[519] Filing Parties July 15, 2010 Filing, Transmittal Letter at 26. *See also* the definition of grandfathered agreement(s) in the Midwest ISO Tariff:

> An agreement or agreements executed or committed to prior to September 16, 1998 or [Independent Transmission Company] [g]randfathered [a]greements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, section 1.276.

a. Comments

446. Minnesota Commission-Minnesota Security ask the Commission to order Filing Parties to revise their filing to not exempt loads under grandfathered agreements from sharing in MVP costs.[520] They note that grandfathered agreements are held by some, but not all, of Midwest ISO's transmission owners, and they argue that the impacts of not allocating costs to load under grandfathered agreements may be more significant for those transmission-owning utilities holding grandfathered agreements because any costs not charged to grandfathered agreement customers are unfairly borne by the remainder of the customers. Minnesota Commission-Minnesota Security also assert that most grandfathered agreements are many years old and rely on the historically existing transmission system to supply the power under the terms of the grandfathered agreements. However, states Minnesota Commission-Minnesota Security, Midwest ISO's studies show that MVPs would provide measurable benefits to all customers in the Midwest ISO footprint, including grandfathered agreement customers. Minnesota Commission-Minnesota Security also point to the Transmission NOPR, which they believe addresses this issue when the Transmission NOPR cited a District of Columbia Circuit Court case and concluded, "[a]fter stating that the subject costs were the administrative costs of having an ISO, the D.C. Circuit found that the Commission correctly determined that bundled and grandfathered loads should share the costs of having an ISO because they drew benefits from Midwest ISO."[521] Minnesota Commission-Minnesota Security state that, since grandfathered agreement loads are included in the required metrics and thresholds studies, grandfathered agreement loads benefit to the same extent as other loads and should, according to the basic premise of the Commission's Transmission NOPR and the courts, share in the costs of the projects from which they benefit.

447. NIPSCO asserts that charges for facilities built to meet public policy requirements should apply to grandfathered agreements to the extent that those public policy requirements apply to entities subject to grandfathered agreements. Moreover, if an entity with load under a grandfathered agreement builds an MVP and receives revenues from other Midwest ISO load, fairness requires that the entity pay charges for MVPs built by others in Midwest ISO.[522]

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[520] Minnesota Commission-Minnesota Security Comments at 6.

[521] *Id.* (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 146).

[522] NIPSCO Comments at 7.

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b. Answers

448. Filing Parties answer that this issue would be better addressed in a separate proceeding, where the grandfathered agreement exemption for both Schedules 26 and 26-A could be considered, and the matter could receive the attention that it deserves, rather than trying to resolve it as a subset of the many issues already presented in this proceeding.[523]

449. Michigan Agencies reply that they each are a party to certain carved-out grandfathered agreements.[524] These parties state that it is highly disturbing for Midwest ISO to suggest that this is an issue that deserves attention, rather than making clear that the policy of carved-out grandfathered agreements has been established for years (since Midwest ISO launched its Day 2 energy markets), that the amount of load served by such grandfathered agreements has decreased and will continue to decrease as the various grandfathered agreements expire by their own terms, and that Midwest ISO's own reports to the Commission on grandfathered agreements have consistently concluded that grandfathered agreements are not disrupting the Midwest ISO markets. Finally, Michigan Agencies state that arguments that they benefit from the system no differently than non- grandfathered agreements transactions are old and untrue arguments.[525]

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[523] Filing Parties October 18, 2010 Answer at 26, n.85.

[524] *See* the definition of carved-out grandfathered agreement(s) in the Midwest ISO Tariff:

> Any [g]randfathered [a]greement(s) that the Commission has identified as "carved out" pursuant to Appendix B of the Commission's September 16, 2004 order, *Midwest* [*Indep.*] *Transmission* [*Sys.*] *Operator, Inc.*, 108 FERC ¶ 61,236 (2004) or that meet the criteria in [s]ection 38.8.3(A).b, and set forth in Attachment P to this Tariff, as that Attachment may be amended from time to time.

Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, section 1.68.

[525] Michigan Agencies November 1, 2010 Answer at 2, 3.

c. Commission Determination

450. We will accept the proposal to exclude grandfathered agreements from the regional allocation of MVP costs under Schedule 26-A. We find that this treatment is consistent with the existing exclusion of grandfathered agreements from the regional allocation of the costs of other network upgrades under Schedule 26.

451. Consistent with our finding elsewhere in this order, we agree with the general notion that MVPs benefit parties under grandfathered agreements. However, we disagree with the conclusion that customers to grandfathered agreements would benefit without an associated contribution to MVP costs. Grandfathered agreements predate the existence of Midwest ISO, and thus, the rate design for service under such agreements does not reflect the regional rate design and cost allocation that applies to service taken under the Tariff (i.e., to agreements that are not grandfathered). Instead, each transmission owner recovers the costs of the transmission facilities used to provide service to grandfathered agreements (including any Baseline Reliability Projects, Market Efficiency Projects, and MVPs on its system) directly from the customer under the grandfathered agreement, and each grandfathered agreement customer pays separate charges to each transmission owner from whom it takes grandfathered service (i.e., a pre-RTO pancaked rate design).[526]

452. We also note that the divisor of the network upgrade charge in Attachment GG includes the contract demand of grandfathered agreements that reflect a pancaked rate design and thus reflects an allocation of the cost of Baseline Reliability Projects and Market Efficiency Projects to grandfathered service agreements.[527] Similarly, we find that, in its compliance filing due 60 days from the date of this order, Midwest ISO must clarify that the divisor of the MVP usage charge in Attachment MM in fact reflects the MWhs of grandfathered service provided by each transmission owner to reflect an allocation of the costs of MVPs recovered under grandfathered agreements.

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[526] *See Midwest Indep. Transmission Sys. Operator, Inc., et al*., Opinion No. 453, 97 FERC ¶ 61,033, at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand*, 102 FERC ¶ 61,192 (2003), *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom. Midwest ISO Transmission Owners, et al. v. FERC*, No. 02-1121, *et al*. (D.C. Cir. 2004).

[527] *See* Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. GG, section 2.d (the network upgrade charge divisor is the same divisor used in Attachment O of the Tariff and in footnote S to the General Rate Formula Template under Attachment O of the Tariff).

E. Exiting and Entering Transmission Owners

453. Filing Parties propose that a Transmission Owner that withdraws from Midwest ISO will remain responsible for all financial obligations incurred under Attachment FF while a member of Midwest ISO.[528]

1. Comments

454. Several parties[529] protest the seemingly contradictory language in the proposal regarding if and how withdrawing Transmission Owners will be charged for MVP costs. Duke states that while MVP cost allocation is based on usage over time according to Midwest ISO, the Curran testimony states that "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."[530] Duke states that this means that MVP cost allocation is based on megawatt hours of actual usage of the transmission system, rather than actual or forecast peak load. However, Duke points to a later statement in Curran's testimony, which states that "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

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[528] *See* Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Att. FF, First Revised Sheet No. 3840. Midwest ISO proposes the following change: "A ~~Party~~ Transmission Owner that withdraws from the Midwest ISO as a Transmission Owner shall remain responsible for all financial obligations incurred pursuant to this Attachment FF while a Member of the Midwest ISO and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Midwest ISO and the withdrawing Member."

Party(ies) is currently defined as "The Transmission Provider, [Independent Transmission Company] where appropriate, Market Participants, Transmission Customers and Transmission Customers, or any combination of the above." Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, First Revised Sheet No. 240.

[529] AMP, ATC, Duke, FirstEnergy, Illinois Commission, and PJM.

[530] Duke Comments at 1 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 10).

Owner withdraws from the Midwest ISO, but after the Transmission Owner becomes a member of the Midwest ISO."[531]

455. Duke seeks clarification on this issue, asserting that nothing in the proposed Tariff language supports Curran's statement. In the alternative, if Duke's interpretation of the proposed language is deemed incorrect and Duke will be financially responsible for MVP cost allocation after leaving Midwest ISO, Duke states that this is unduly discriminatory. Duke states that it is unduly discriminatory to charge an entity that leaves Midwest ISO based upon its historic demand or historic usage of the transmission system, while charging others based on their current use of the system.[532]

456. FirstEnergy states that under no circumstances should Midwest ISO allocate MVP costs to ATSI or the ATSI utilities.[533] ATSI and the ATSI utilities are withdrawing from Midwest ISO and will be fully integrated into PJM on June 1, 2011.[534] FirstEnergy states that, although MVP costs will be recovered through a usage charge, Midwest ISO proposes an effective date for this proposal of July 16, 2010, in what FirstEnergy views as an attempt to obtain approval of MVPs. Further, FirstEnergy states that even if the MVP proposal, as written, permitted Midwest ISO to charge ATSI, as a withdrawing Transmission Owner, for MVP costs, Midwest ISO is precluded from modifying the rights and obligations of a withdrawing Transmission Owner by means of an FPA section 205 filing.[535]

457. As a primary matter, FirstEnergy notes that under the Midwest ISO Tariff for both Baseline Reliability Projects and Market Efficiency Projects, costs are allocated to

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[531] *Id.* at 3 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 40); *see also* AMP Comments at 18-19; ATC Comments at 9-10.

[532] Duke Comments at 4. Minnesota Commission-Minnesota Security contend that transmission owners leaving Midwest ISO pay for studies pertaining to reliability, interconnection, operations, and markets, but they do not pay the full administrative and study costs of leaving. Minnesota Commission-Minnesota Security recommend that the Commission order Midwest ISO to work with its members to revise the procedures for leaving Midwest ISO to obligate a member to pay the full cost involved. Minnesota Commission-Minnesota Security Comments at 7.

[533] FirstEnergy Comments at 21.

[534] *Id*. at 2.

[535] *Id*. at 21.

Transmission Customers only, and under the Midwest ISO Tariff, a Transmission Owner is not a Transmission Customer. Further, the responsibilities of a withdrawing party extend only to Parties, and Transmission Owner is not included in the definition of Party(ies).[536] FirstEnergy cites as evidence of Midwest ISO's intention to allocate costs to ATSI and the ATSI Utilities, Midwest ISO's inclusion of their load in its study of the Michigan Thumb Project as an MVP, assigning ATSI approximately 11.5 percent of the cost.[537] FirstEnergy states that Midwest ISO has not shown that its apparent intent to allocate MVP costs to load in the ATSI zone and require ATSI to pay such costs upon withdrawal is fair, reasonable, and "roughly commensurate" with the benefits to load in the ATSI zone.[538] Finally, FirstEnergy argues that further proof that Midwest ISO has no justification for allocating costs to ATSI upon its withdrawal from Midwest ISO, are ATSI's timely actions taken to join PJM[539] and the fact that Midwest ISO removed the ATSI zone from Midwest ISO in its transmission planning models in analyzing the Michigan Thumb Project.

458. Duke and FirstEnergy cite the Commission's findings upon Duquesne Light Company's request to leave PJM. In that case, the Commission determined that Duquesne could not avoid paying for capacity that PJM had already acquired on its behalf, but that, because Duquesne's withdrawal plan was otherwise acceptable and absent reliance concerns, it was appropriate to honor Duquesne's request to be excluded

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[536] *Id*. at 24-25 (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, section II.1.494, First Revised Sheet No. 240). The Midwest ISO Tariff reads, "Party(ies): The Transmission Provider, [Independent Transmission Company] where appropriate, Market Participants, Transmission Customers and Transmission Customers, or any combination of the above."

[537] *Id*. at 28.

[538] *Id*. at 34 (citing *Illinois Commerce Commission*, 576 F.3d at 476).

[539] These include: i) commitment of the ATSI utilities' respective loads into the PJM capacity auctions for the 2013-2014 planning year; ii) conducting auctions for procuring all of the PJM-qualified capacity necessary to meet the ATSI zone's capacity obligations for the 2011-2012 and 2012-2013 delivery years and executing the related, legally-binding bilateral unit-specific capacity purchase and sale agreements with the capacity resources that cleared in each auction obligating them to pay a total of nearly $600 million for the capacity procured through the auctions; and iii) participating in PJM's RTEP planning process. *Id.* at 36.

from the May 2008 auction, for which PJM had not yet published its parameters.[540] The Commission found that Duquesne would no longer be required to pay PJM's regional transmission expansion planning costs upon its departure from PJM. The Commission determined that the PJM tariff requires PJM to allocate RTEP costs based upon load-ratio share, and that PJM was required by its tariff to recalculate load-ratio share on an annual basis "to reflect PJM's then-existing zones and loads."[541] FirstEnergy states that Midwest ISO has no authority to impose such significant additional financial burdens on the Midwest ISO transmission owners, that Midwest ISO offers no justification for the proposed revision, and that this change is unrelated to, and unnecessary to implement, the MVP. FirstEnergy, further, states that nowhere does the Transmission Owners Agreement provide for or authorize Midwest ISO unilaterally to create significant, new financial obligations. Thus, FirstEnergy recommends that the Commission reject the proposed change.[542]

459. AMP states that Midwest ISO proposes to continue to charge Transmission Owners for the full value of MVP approved while the Transmission Owners are members, even after they withdraw from Midwest ISO. This fails to allocate responsibility equitably, according to AMP.[543] AMP believes that Midwest ISO's proposal should be revised such that if an existing Transmission Owner departs from Midwest ISO, then customers within the relevant transmission zone should not be charged the MVP usage rate, which would more accurately reflect usage of the relevant MVP facilities.[544] AMP also describes a case where a Transmission Owner withdraws from Midwest ISO, but the load in the relevant Transmission Owner's zone has a resource that remains within Midwest ISO. In such an instance, AMP states, Midwest ISO would impermissibly double charge both the MVP rate and the export charge. AMP requests that the Commission, at a minimum, require Midwest ISO to ensure that no

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[540] *Id.* at 32 (citing *Duquesne Light Co.*, 122 FERC ¶ 61,039, at P 96 (2008), *order on reh'g*, 124 FERC ¶ 61,219 (2009) (September 3, 2008 Order), *reh'g pending*).

[541] Duke Comments at 4-5 (citing September 3, 2008 Order, 124 FERC ¶ 61,219 at P 162-177).

[542] FirstEnergy Comments at 28-29.

[543] AMP Comments at 18-19.

[544] *Id*. at 19.

double charge occurs, and preferably eliminate both the export charge and the withdrawal charge.[545]

460. Illinois Commission recommends that the Commission direct Midwest ISO to clarify its position regarding changing transmission system use and changing MVP use over time and to clarify its MVP rate design proposal.[546] PJM presents arguments similar to FirstEnergy and others, that Transmission Owners that withdraw from Midwest ISO cannot be allocated costs for MVP transmission projects when the MVP category did not exist when those Transmission Owners made their decision to withdraw. PJM cites ATSI, which received Commission approval on December 17, 2009, to withdraw from Midwest ISO and join PJM in 2011.[547] PJM also seeks clarification of the proposal to charge withdrawing Transmission Owners for MVP costs since the MVP usage rate is based on actual usage. PJM states that Midwest ISO has provided no explanation of how such a charge will be calculated for a Transmission Owner that is no longer a member of Midwest ISO.[548]

461. ATC and FirstEnergy also object to the proposed revision to Original Sheet No. 3480 of Attachment FF proposed by Midwest ISO as unclear regarding the purpose and meaning of the proposed change. ATC states that all parties, whether Transmission Owners, Transmission Customers, or any other party, must fulfill their financial obligations upon withdrawal from Midwest ISO. If there are no financial obligations in the first instance, ATC states, the proposed language does nothing more than reduce the range of current members that may have financial obligations to Midwest ISO and its remaining Transmission Owners. ATC recommends that the Commission reject this proposed change.[549]

462. Finally, NextEra expresses concern that Transmission Owners may base their decisions to withdraw from an RTO on short-term economic concerns rather than a long-

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[545] *Id*. at 19-20.

[546] Illinois Commission Comments at 53.

[547] PJM Comments at 13.

[548] *Id*. at 14.

[549] ATC Comments at 9-10.

term view. NextEra urges the Commission to give the utmost scrutiny to any withdrawal proposals and to not approve a withdrawal unless it is found to be just and reasonable.[550]

2. Answers

463. In response to protestor comments in regard to withdrawing load-serving entities, as a first matter, Filing Parties contend that these issues are beyond the scope of this proceeding. Regarding objections to the proposed change in Attachment FF, Filing Parties state that changing the word "party" to "Transmission Owner" is consistent with the terminology and intent of the Transmission Owners Agreement, and clarifies that the provision covers withdrawal "as a Transmission Owner." They contend that the substance of the provision, which the Commission has been previously accepted as just and reasonable, cannot be collaterally attacked in this proceeding. Filing Parties note that the Transmission Owners Agreement expressly provides that "All financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Midwest ISO and the withdrawing Owner."[551]

464. As to the argument that a withdrawing load-serving entity should not be held liable for any transmission cost allocation from a transmission project approved after the load-serving entity has announced its intent to withdraw, Filing Parties state that this was not the cut-off point established in the *ATSI* withdrawal case, in which the Commission allowed ATSI to be charged for the cost of projects planned and approved before the actual withdrawal date.[552]

465. In response to AMP's argument that the Commission should require Midwest ISO to ensure that no double charging occurs, Filing Parties state that as in the case of any other Transmission Owner withdrawal, it is expected that any credits due to the withdrawing Transmission Owner would offset any of its obligations. Thus, the MVP proposal would not involve any double-billing of withdrawing Transmission Owners.

466. In answer to FirstEnergy's argument regarding the obligations of its affiliated utilities when they leave Midwest ISO and join PJM, ITC Companies state that such

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[550] NextEra Comments at 24-25.

[551] Filing Parties October 18, 2010 Answer at 74 (citing Transmission Owners Agreement, Article Five, section II.B ("Existing Obligations")).

[552] *Id*. at 76-77 (citing *Am. Transmission Sys., Inc. v. PJM Interconnection, LLC*, 129 FERC ¶ 61,249, at P 112-14 in relation to P 94-95, 98 (2009) (*ATSI*)).

issues should be addressed in a separate proceeding, based on the Tariff language approved by the Commission in the instant proceeding.[553]

467. ITC Companies also object to the change to Attachment FF proposed by Midwest ISO. They state that the language as it currently exists has served to address the responsibilities of load in the zone of an existing Midwest ISO member for obligations that arise under Attachment FF, and they recommend that the Commission reject the proposed change. If it is accepted, ITC Companies recommend that the Commission order that it not apply to Independent Transmission Companies, because these companies have no load.[554]

468. AMP and FirstEnergy object to Filing Parties' description of the proposed change in Attachment FF as insubstantial or cosmetic. Because the terms Party and Transmission Owner have different meanings, AMP argues, the change is material, and Filing Parties' argument that this line of questioning is a collateral attack on the Tariff is misplaced.[555] Regarding the issue of double-charging, AMP contends that Filing Parties' answer to their concern is meaningless. AMP states that the issue at hand is whether an embedded load-serving entity with a non-migrating resource will be double-charged. That is, would happen if the embedded load-serving entity were made to pay both: 1) a load ratio or other share of MVP-related costs assigned to ATSI, and 2) in addition, MVP-related costs included in Midwest ISO's proposed export charge for the transmission from Midwest ISO to PJM of energy from a non-migrating resource.[556]

469. FirstEnergy states that the proposed change would result in a very significant cost shift from Parties, as defined in the Tariff, to Transmission Owners. It states that under the existing Tariff, costs of MTEP projects are allocated under Attachment FF to loads in Midwest ISO pricing zones and that Transmission Owners are not subject to charges under Attachment FF. It challenges Filing Parties' reliance on the Transmission Owners Agreement as authority for the proposed change, arguing that while the withdrawal language in Attachment FF may be "based on" Article V, section II.B of the Transmission Owners Agreement, Attachment FF does not impose financial obligations on Transmission Owners. Further, the Commission orders cited by Filing Parties as

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[553] ITC Companies September 27, 2010 Answer at 4.

[554] ITC Companies September 27, 2010 Answer at 13-14.

[555] AMP November 2, 2010 Answer at 4-5.

[556] *Id*. at 12.

authorizing or justifying the imposition of MVP costs on withdrawing Transmission Owners is misplaced; it states that the two orders both arose in the context of Midwest ISO seeking to ensure recovery of costs that it incurred upon start-up, without which Midwest ISO's financial viability would have been jeopardized.[557]

3. Commission Determination

470. The parties raise three distinct issues. First, regarding whether Filing Parties' proposed changes to Attachment FF are just and reasonable, we find that they are just and reasonable, and, further, are consistent with the language of the Transmission Owners Agreement. We reject the argument that the purpose of the proposed changes is unclear. The Transmission Owners Agreement defines the financial obligations that withdrawing transmission owners face.[558] The proposed changes seek to remove ambiguity about the applicability of such obligations to transmission owners and simply brings the Tariff into agreement with the above language.

471. The second issue at hand is whether load that withdraws from Midwest ISO is subject to the MVP usage rate charge for MVPs. As we read the proposal, a transmission owner that withdraws from Midwest ISO would remain responsible for all financial obligations incurred with respect to the MVP Tariff provisions while a member of Midwest ISO. Such amounts would be determined at the time of the withdrawal. We accept Filing Parties' statement that the withdrawing Transmission Owner would receive credits against any MVP usage charges incurred after it withdraws, to the extent necessary to avoid the possibility of withdrawing Transmission Owners being subject to double billing. In addition, a transmission owner that withdraws from Midwest ISO and joins PJM would not be subject to the MVP usage charge for subsequent exports from Midwest ISO to serve its load in PJM. To the extent that such withdrawing transmission owner is subject to an exit fee reflecting MVP costs allocated to its zonal load, the exit fee would not constitute rate pancaking, because the charge would not be transactional,

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[557] FirstEnergy November 2, 2010 Answer at 4-7 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 101 FERC ¶ 61,221, at P 10 (2002); *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,035, at P 2 (2003)).

[558] *See* Transmission Owners Agreement, Art. V, sec. B (Existing Obligations), ("All financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Midwest ISO and the withdrawing owner."); *see also*, March 17, 2006 Order, 114 FERC ¶ 61,282 at P 52-60, *order on reh'g*, 116 FERC ¶ 61,020 (2006) (accepting an exit fee that was submitted pursuant to Article V of the Transmission Owners Agreement).

but would be assessed regardless of where power is sourced to serve that load (from within PJM or imported from Midwest ISO).

472. Third, as to the process of withdrawal and other costs that a particular withdrawing member may face, we find that these issues are beyond the scope of the instant proposal. Such determinations should be made at the time an application to withdraw is made, with the appropriate notice and opportunity for comments.

F. Joint Ownership and Eligibility for Regional Cost Sharing

473. Under Filing Parties' proposed revisions to Attachment FF, a new transmission owner's pre-existing planned transmission projects, pending at the time it joins Midwest ISO, will not be subject to regional cost sharing under the Tariff.

1. Comments

474. Midwest TDUs argue that the proposal should be revised to accommodate Joint Ownership Arrangements. Midwest TDUs contend that the proposed language does not clarify whether a jointly-owned project can qualify as an MVP (or a Baseline Reliability Project or a Market Efficiency Project) if it is owned, in part, by transmission-dependent utilities that are not currently a transmission-owning member of Midwest ISO or that do not apply to be a transmission-owning members until the project is constructed. Midwest TDUs maintain that it would be unduly discriminatory and contrary to the Commission's objectives to facilitate transmission expansion if the proposal limits the potential pool of MVP owners to include only existing transmission-owning members of Midwest ISO. Midwest TDUs argue that joint ownership arrangements galvanize broad support for projects and should be facilitated to assist with the siting and construction of MVPs. Midwest TDUs ask that Filing Parties should be required to clarify or revise this language to avoid increasing barriers to joint ownership arrangements.

2. Answers

475. Filings Parties answer that they oppose allowing new Midwest ISO transmission owners to receive regional cost sharing for their portion of pre-existing, jointly-owned projects that were planned before their integration as transmission-owning members. They contend that this is an established practice and is not a change from existing policy and practice. They argue that the Commission has made clear that a prospective transmission owner's pre-existing planned transmission projects, pending at the time when it joins Midwest ISO, are not subject to regional cost sharing under the Midwest ISO Tariff.[559] Filing Parties support this policy because such pre-existing projects would

[559] Filing Parties state that the Commission applied this policy to the recent

(continued…)

not have been planned under the Midwest ISO regional planning process and new Midwest ISO transmission owners would not be assigned costs for regional projects submitted to the Midwest ISO Board prior to their integration. Filing Parties oppose granting Midwest TDUs an exception for the purposes of jointly-owned projects because an entity should enjoy the benefits of being a Midwest ISO transmission owner (e.g., regional cost sharing for some of its facilities) only when it accedes to the many responsibilities of that status (e.g., ceding operational control over its transmission and mandatory participation in the MTEP process). They state that the Commission has been skeptical of past proposals to create special rules to allow entities to receive the benefits of Midwest ISO participation while escaping some of the costs,[560] and the Commission should apply similar skepticism here.

476. Midwest TDUs respond that Filing Parties' position is a clear departure from prior practice. They state that, in 2008, Midwest ISO repeatedly confirmed that the joint ownership shares of Midwest TDUs in the CapX 2020 projects would be eligible for regional cost sharing on the same basis as existing Midwest ISO transmission owners.[561] Midwest TDUs contend that they seek to maintain the status quo and to require Midwest ISO to stand by the assurances that it has provided to WPPI and MRES. Further, they assert that limiting cost allocation to the pricing zone where the facility is located would discourage joint ownership in projects.

3. Commission Determination

477. We deny Midwest TDUs' request to require Filing Parties to revise the MVP proposal to further accommodate Joint Ownership Arrangements because this request is outside of the scope of this proceeding. Concerns about which projects of a new transmission-owning member will be subject to the Midwest ISO regional planning process and which of its transmission projects will be subject to cost allocation pursuant to Attachment FF should be raised when a prospective Transmission Owner applies to

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integrations of MidAmerican and Dairyland as Midwest ISO transmission owners. Filing Parties October 18, 2010 Answer at 82 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 128 FERC ¶ 61,046, at P 61 (2009); *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,187, at P 14 (2010) (May 28, 2010 Order)).

[560] *Id.* at 84 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 126 FERC ¶ 61,139, at P 66-71 (2009)).

[561] Midwest TDUs November 2, 2010 Answer at 3-8 (citing telephone and email discussion between representatives of Midwest ISO and representatives of WPPI and MRES).

join Midwest ISO.[562] Insofar as Midwest TDUs seek compensation for facilities prior to becoming a transmission-owning member and transferring control of such facilities to Midwest ISO, that request is beyond the scope of this proceeding.

G. Effective Date

478. As noted above, Filing Parties request waiver of the prior notice requirement to permit the proposed Tariff revisions in the July 15 Filing to become effective on July 16, 2010. They state that such an effective date is necessary and appropriate to provide guidance and certainty in connection with pending public policy-driven transmission project proposals and with respect to the generator interconnection process. According to Filing Parties, the July 16, 2010 effective date was selected to apply MVP cost allocation for transmission projects that may be approved in Appendix A of the 2010 MTEP. They state that this effective date would allow Midwest ISO to apply the MVP criteria to those 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 for approval in December 2010.[563] They also claim that it is consistent with the Commission's directive in the October 23, 2009 Order to adopt subsequent Tariff revisions by July 15, 2010, and given that directive, stakeholders have been on notice that changes in the Midwest ISO cost allocation methodology were forthcoming.[564]

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[562] *See* May 28, 2010 Order, 131 FERC ¶ 61,187 at P 14 (explaining that when projects will be subject to the Midwest ISO regional planning process and which transmission projects will be subject to cost allocation pursuant to Attachment FF is an issue associated with the integration of any new transmission-owning member into the Midwest ISO regional planning process).

[563] The Commission notes that on December 2, 2010, the Midwest ISO Board voted on MTEP 2010.

[564] Filing Parties July 15, 2010 Filing, Transmittal Letter at 40.

1. Comments

479. Several parties oppose a July 16, 2010, effective date.[565] Some argue that Filing Parties have not shown good cause for waiver of the prior notice requirement, because: 1) the potential consequences of not obtaining waiver of notice that are cited by Filing Parties are speculative; 2) the request for waiver does not address the impact that a waiver of notice would have on customers, as required by section 35.11 of the Commission's regulations; 3) under Commission precedent, waiver of notice is denied where rate increases or the effective date are not prescribed by agreement or contract; and 4) Filing Parties do not cite to an emergency such as the unanticipated consequences affecting Otter Tail and Montana-Dakota Utilities when Filing Parties sought approval of the interim cost allocation methodology.

480. In addition, commenters argue that: 1) the proposed effective date does not afford stakeholders a sufficient opportunity to review and propose alteratives to the proposal;[566] and 2) the proposed effective date would allow the proposed allocation to apply to the FirstEnergy and Duke zones prior to their withdrawal from Midwest ISO, and their customers would become financially responsible for those transmission upgrades with no corresponding benefits.

481. Indiana Commission and NIPSCO argue that a July 16, 2010, effective date would mean that no other market participant or other entity would have the opportunity to propose alternatives to the fast-tracked project approved by the Midwest ISO Board. Therefore, NIPSCO states, the planning process for MVPs should start at the beginning of the Midwest ISO planning process. NIPSCO suggests that the Commission make the effective date of the MVP cost allocation methodology the same as the date Midwest ISO begins the next MTEP process.

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[565] *See* AMP Comments at 12-13; FirstEnergy Comments at 46-54; Illinois Commission Comments at 54-56 (opposing requested effective date with respect to the MVP cost allocation proposal); Indiana OUCC Comments at 4; Indiana Commission Comments at 4; Minnesota Commission-Minnesota Security Comments at 5-6; NIPSCO Comments at 8-9; OCC Comments at 11-14; MICH-CARE Comments at 8.

[566] For example, Indiana Commission and NIPSCO argue that a July 16, 2010 effective date would mean that no other market participant or other entity would have the opportunity to propose alternatives to the fast-tracked project approved by the Midwest ISO Board. Therefore, NIPSCO states, the planning process for MVPs should start at the beginning of the Midwest ISO planning process.

482. OCC and FirstEnergy argue that the proposed cost allocation methodology that would result from the 19-month stakeholder process has been a work in progress and has constantly shifted throughout the process and that the instant proposal is very different from what stakeholders were originally presented to consider. OCC urges the Commission not to set an effective date until stakeholders have had sufficient time to comment both on the proposed cost allocation methodology and on projects that may qualify as MVPs and whose costs may be charged to them. FirstEnergy argues that the process was never approved by the RECB Task Force or the OMS CARP, and that it was not the approach that the Midwest ISO Advisory Committee preferred. FirstEnergy argues that the proposal should be rejected so that stakeholders can have an opportunity to fully evaluate it. FirstEnergy asks the Commission to confirm that Midwest ISO is not, and will not be, authorized to consider and approve MVPs until the Commission accepts and makes effective the Tariff revisions proposed in this proceeding.

483. Indiana OUCC expresses conditional support for the overall Midwest ISO approach contingent upon, among things, that the effective date should be postponed to allow parties which have not been deeply involved in the review of already-proposed projects to have ample time to do so. Several parties request that the Commission suspend Filing Parties' filing and set it for hearing.[567] For example, ABATE, Industrial Customers and MISO Northeast Transmission Customers argue that the MVP cost allocation methodology proposal raises numerous factual issues that require discovery and an evidentiary hearing.

484. Opponents of a July 16, 2010 effective date argue for various alternative effective dates: 1) 60 days from the date of filing; 2) after five months suspension; 3) no earlier than the date the Commission accepts the proposal; 4) no earlier than December 2011, to coincide with the time when the 2011 MTEP can be approved by the Midwest ISO Board; and 5) after the Commission establishes standards for MVPs in the Transmission NOPR proceeding.

485. In addition, Minnesota Commission-Minnesota Security argue that the multi-billion dollar CapX 2020 transmission upgrade proposal benefits neighboring states, relieves congestion and assists in fulfilling Minnesota's renewable energy mandate but is arbitrarily excluded from MVP status because any projects approved by the Midwest ISO Board before July 15, 2010 will be treated as existing lines under Midwest ISO's prior RECB cost allocation method. Minnesota Commission-Minnesota Security urge the

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[567] ABATE Comments at 5; FirstEnergy Comments at 49-50; Illinois Commission Comments at 55; Industrial Customers at 45; MISO Northeast Transmission Customers Comments at 34; Hoosier-SIPC Comments at 23-24.

Commission to order Midwest ISO to allow the CapX 2020 projects that have been approved but have not yet commenced construction to apply for MVP status so that they could become eligible as MVPs for cost sharing under the cost allocation and rate design methods ultimately approved by the Commission.

486. IPL requests that, if the Commission moves forward with the instant proposal, and if it finds IPL's proposals for modifying the proposal to be promising but is not prepared to direct that the proposal incorporate such features in a compliance filing, then the Commission should establish settlement judge procedures as a way to resolve remaining issues.[568] Steel Producers argue that the filing is deficient because it fails to identify the specific requirements that Filing Parties want the Commission to waive and, thus, fails to satisfy the Commission's tariff filing requirements in section 35.13 of the Commission's regulations.

487. ITC Companies-Wolverine and Michigan Commission support the requested July 16, 2010 effective date. Citing the Michigan Thumb Project, which was approved by the Midwest ISO Board on August 19, 2010,[569] ITC Companies-Wolverine assert that any delay in the proposed effective date would at the very least introduce uncertainty and at the worst call into question the cost allocation that will be available for projects included in the 2010 MTEP. Delaying the effective date could delay realization of the benefits of new MVP, according to ITC Companies-Wolverine.[570] Michigan Commission states that it strongly supports the requested effective date as consistent with stakeholder discussions and expectations to date by allowing MVP cost allocation treatment for projects that may be approved in Appendix A of the 2010 MTEP.[571] MidAmerican supports the proposed

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[568] IPL Comments at 41.

[569] ITC Companies-Wolverine explain that the Michigan Thumb Project is an approximately 140 mile, double circuit 345 kV transmission line and three new substations that will form a loop through the Thumb region of the Lower Peninsula of Michigan. They state that the project was designed to facilitate a State Renewable Portfolio Standard and other public policy objectives and will serve as the backbone of a transmission system designed to deliver wind power from the Thumb area. ITC Companies-Wolverine Comments at 18.

[570] *Id*.

[571] Michigan Commission Comments at 18.

requirement that projects must be approved after July 15, 2010, by the Midwest ISO Board to be eligible for consideration as an MVP.[572]

488. Illinois Commission does not oppose a July 16, 2010, effective date for the proposed SNUs proposal to address the "first mover/late comer" issue in the generator interconnection queue process.[573]

489. Several commenters expressed concern with the sufficiency of the stakeholder process.[574] For example, Designated PJM Parties argue that Filing Parties did not coordinate with other affected parties, including PJM and its load-serving entities. Thus, they claim that the MVP proposal is predicated on unsupported conjecture about circumstances external to Midwest ISO and ignores a host of relevant facts, such as the extent to which Renewable Portfolio Standards requirements in PJM states can be satisfied by local generation and transmission options, including wind generation. IPL argues that the proposal is not generally supported by participants across the region, stating that less than half of transmission owners signed on to the proposal.

490. Wisconsin Commission argues that while the stakeholders may, in the open light, craft a solution to a problem at hand, the RTO's ultimate decision may be made outside of the stakeholder process between the RTO and the large transmission owners threatening to leave. It urges the Commission to consider changing RTO rules to avoid undue influence from individual transmission owners and ensure that decisions are made with the public interest considered.

491. AWEA-WOW and Indiana OUCC express favorable views of the stakeholder process that led to the instant filings.[575] AWEA-WOW state that: 1) the MVP proposal was developed through a collaborative process with state authorities and participants across the Midwest ISO region; 2) the MVP proposal's broad regional support is reflected in the stakeholder process; and 3) many states support the final MVP proposal. Indiana OUCC states that there is significant value in the development of a proposal by

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[572] MidAmerican Comments at 25-26.

[573] Illinois Commission Comments at 3, 54. Illinois Commission does oppose the requested July 16, 2010 effective date with respect to the MVP cost allocation proposal, as noted below.

[574] Designated PJM Parties Comments at 3-5; DP&L Comments at 3; IPL Comments at 11-13, Wisconsin Commission Comments at 5-6.

[575] AWEA-WOW Comments at 21-22; Indiana OUCC Comments at 3.

stakeholders in the region and that it was actively involved in the stakeholder process. Indiana OUCC believes that the proposal incorporates much of what stakeholders in the CARP and RECB meetings were able to agree with.

2. Answers

492. Filing Parties respond that: 1) there is no basis for rejection of the filing, because it is fully supported; 2) Filing Parties submitted all information required under section 35.13 for a filing that does not change rates, and they expressly noted that most requirements of section 35.13 are inapplicable to cost allocation filings; and 3) a trial-type hearing is unnecessary because no issues have been raised with the filing that cannot be resolved on the written record. Regarding the request for settlement procedures, Filing Parties argue that the Commission typically does not set a matter for settlement judge procedures that it has not also set for evidentiary hearing, and no such hearing is required. Further, since the July 15 Filing already reflects nearly a year of extensive stakeholder negotiations, it is not clear that further negotiations through settlement judge procedures would warrant delaying implementation of the proposal.[576]

493. Filing Parties also reiterate their support for a July 16, 2010, effective date, arguing that the July 9 filing, the October 23, 2009 Order and the extensive and open stakeholder process were sufficient to provide the parties with notice that changes to the Midwest ISO cost allocation methodology were coming, and provide good cause for granting the requested effective date. Regarding concerns that the requested effective date will not afford stakeholders sufficient time to review proposed transmission projects, Filing Parties state that all transmission projects will follow the same transmission planning processes in accordance with Order No. 890 independent of the approved effective date. They further state that granting the requested effective date would allow for prompt implementation of the MVP and SNU mechanisms and avoid uncertainty and additional costs for interconnection customers.[577] They also argue that a five months suspension is not justified, because no rate increase has been filed and no further procedures are needed to decide this filing.

494. Further, Filing Parties argue that there is no need to delay action on the proposal until the Commission issues a final rule on the Transmission NOPR. They argue that the proposal is designed to conform to the guidance contained in the Transmission NOPR and that it is uncertain when the Commission will issue a final rule or what the

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[576] Filing Parties October 18, 2010 Answer at 91-95.

[577] *Id.* at 95-97.

requirements of that rule will be. Further, the Commission has not established any moratorium on cost allocation changes while the Transmission NOPR is pending.[578]

495. MidAmerican argues that AMP's suggestion to time the upgrades that are eligible for MVP cost allocation with the Commission's order on the MVP cost allocation methodology would chill the construction of major new transmission in the Midwest ISO footprint. According to MidAmerican, many transmission facility concepts that would be logical candidates for an MVP designation could be considered to be projects already submitted for review by Midwest ISO, which would prevent the implementation of the MVP cost allocation in a timely manner and substantially delay the construction of needed new transmission facilities.[579]

496. Further, while MidAmerican recognizes the need of stakeholders to have the opportunity to review and comment on the planning of new transmission facilities prior to sharing in the costs of such facilities, it contends that a December 2011 effective date as proposed by OCC would unnecessarily delay the approval of projects as qualifying for MVP cost allocations. Therefore, MidAmerican supports consideration of delaying the effective date to July 1, 2011, provided that already-proposed (but not in-service, not under construction, or not already approved) projects prior to July 1, 2011, are eligible for consideration as MVPs. MidAmerican states that if such a change is adopted, this will increase the time stakeholders are allowed to review and comment on projects that become eligible for MVP cost allocation without unnecessarily delaying the approval of projects qualifying for MVP cost allocation.[580] MISO Northeast Transmission Customers state that, if the Commission provides for a later effective date, they argue that it should, at a minimum, require that projects that are included in Appendix A of the 2010 MTEP be eligible for MVP cost allocation.[581]

497. MidAmerican opposes altering the effective date to allow specific projects – such as the CapX2020 projects – to be eligible for MVP designation because that would provide preference to those projects over other projects that are potentially just as or more deserving of designation as MVPs.[582]

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[578] *Id*. at 98-99.

[579] MidAmerican September 27, 2010 Answer at 7.

[580] *Id*. at 8.

[581] MISO Northeast Transmission Customers September 27, 2010 Answer at 5-6.

[582] MidAmerican September 27, 2010 Answer at 8-9.

498. ITC Companies note that the Commission granted waiver of notice to New York ISO to allow a tariff revision to take effect one day after filing, where it found that New York ISO's stakeholder process had provided six months actual notice of the filing in that case.[583] ITC Companies also note the October 23, 2009 Order's grant of a waiver of notice to allow the interim cost allocation proposal to become effective one day after filing, and that the Commission cited the ample notice of that filing through the stakeholder process that preceded the filing.

499. AMP contends that Filing Parties' reliance on the October 23, 2009 Order is misplaced, because there is no indication in that order that the Commission intended for the long-term cost allocation methodology to be made effective on any specified date. AMP states that it is more reasonable to presume that the Commission intended that its regulations, including the 60-day notice requirement, would be followed. Further, while stakeholders were on notice that a replacement methodology for the interim methodology was forthcoming, AMP disputes that stakeholders should be considered on notice that the effective date would be anything other than one established in full compliance with the Commission's regulations, including the 60-day notice requirement. In addition, Midwest ISO's Transmission Planning Business Practice Manual does not mention MVPs in its listing of project categories for cost allocation purposes.[584]

500. Regarding Filing Parties' arguments concerning delay and uncertainty, AMP responds that such arguments are based on the threat that, unless their request is granted, some set of wind-related upgrades the Commission might favor will not get built. AMP argues that the Commission should recognize that there are limits on the extent to which procedural regularity may be bent in the interest of serving any particular set of public policy goals and that the waiver request would take the Commission beyond those limits.[585]

501. AMP suggests that the only plausible rationale for Filing Parties' waiver request is that they deem it important, in order to assign a share of the Michigan Thumb Project's costs to ATSI, to have the MVP provisions made effective before the date on which the Midwest ISO Board approved the Michigan Thumb Project for inclusion in Appendix A of the MTEP. Yet, argues AMP, Filing Parties have argued that a departing Transmission Owner is responsible for the costs of projects planned and approved before

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[583] ITC Companies September 27, 2010 Answer at 7-10 (citing *New York Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,238, at P 36 (2008) (September 12, 2008 Order)).

[584] AMP November 2, 2010 Answer at 7-9.

[585] *Id*. at 9-10.

the date of the Transmission Owner's actual withdrawal. If that were so, the waiver request would be unnecessary because Midwest ISO and the Midwest ISO Board would have until June of next year, when ATSI's withdrawal is complete, to get the MVP provisions into effect and have the Midwest ISO Board act. Thus, AMP asserts, Filing Parties' waiver request is simply an effort to hedge their bets on the assignment of Michigan Thumb Project costs to ATSI. AMP argues that this does not rise to the level of good cause for waiver.[586]

502. Regarding the stakeholder process, Filing Parties state that, prior to July 15, 2010, Midwest ISO engaged in over 30 meetings with state regulators and stakeholders since the July 9, 2009, interim cost allocation filing. The filed MVP proposal involves "minor tweaks" of the supporting Transmission Owner proposal and the OMS CARP proposal, and the common theme among these proposals is the provision for broad regional sharing to load of projects intended to integrate renewable energy projects. Thus, Filing Parties disagree that the MVP proposal represents a fundamental shift in the types of cost allocation methodologies that had been reviewed and supported through the stakeholder process.[587]

3. Commission Determination

503. We grant waiver of the 60-day prior notice requirement to permit an effective date of July 16, 2010, for good cause shown.[588] Where the Commission has directed an applicant to conduct a stakeholder process that would result in the applicant making a new filing, as the Commission did in the October 23, 2009 Order where it stated that Midwest ISO was expected to file a long-term cost allocation proposal on or before July 15, 2010, the Commission has found that stakeholders were put on notice of such filing.[589] In this instance, stakeholders had approximately nine months prior notice of the instant filing.

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[586] *Id*. at 10-11.

[587] Filing Parties October 18, 2010 Answer at 90.

[588] 16 U.S.C. § 824d (2006); 18 C.F.R. § 35.11 (2010); *Central Hudson Gas & Electric Corp*., 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089 (1992).

[589] *See*, *e.g*., September 12, 2008 Order, 124 FERC ¶ 61,238 at P 36 (finding good cause for waiver, noting that the stakeholder process provided actual notice of the filing); *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,169, at P 26, *order on reh'g*, 115 FERC ¶ 61,293 (2006) (same); *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,245, at P 6 (2006) (finding good cause for waiver based, in part, on the stakeholder

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504. We thus disagree with arguments that stakeholders were not afforded sufficient opportunity to review the instant proposal or that the perceived inadequacy of that process should provide a basis for delaying the effective date. As directed by the October 23, 2009 Order, Filing Parties submitted quarterly informational status reports on the stakeholder process leading up to the July 15 Filing. These quarterly reports described the proposals that were under consideration by the stakeholders and the actions taken on such proposals.[590] In addition, the quarterly reports indicate that stakeholder participation in the development of the instant proposal was generally open, transparent and collaborative.

505. In addition, stakeholders have been afforded an opportunity to challenge the instant proposal through the notice and comment procedures in this proceeding, including an extended time for comments. Further, as Filing Parties note, all transmission projects including the MVPs will follow the transmission planning processes required by Order No. 890 independent of the effective date adopted here.

The Commission orders:

(A) Filing Parties' request for waiver of the prior notice requirement is hereby granted, as discussed in the body of the order.

(B) Filing Parties' proposed Tariff revisions are hereby conditionally accepted for filing, to become effective on July 16, 2010, as discussed in the body of this order.

(C) Filing Parties are hereby directed to submit a compliance filing within 60 days of the date of this order, as discussed in the body of this order.

(D) Filing Parties are hereby directed to submit a further compliance filing on

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process that preceded the filing).

[590] With respect to arguments that Filing Parties have not satisfied the requirements of section 35.11, we disagree. We disagree that the potential consequences of not obtaining a waiver of notice are merely speculative, for the reasons cited by Filing Parties and their witness Moeller, cited above. In addition, the application indicates how costs will be allocated under its proposal, and the effective date has a bearing on which projects will be eligible for regional cost sharing; thus, it does address the effects of the July 16, 2010 effective date on customers. Further, the instant application concerns cost allocation, not a revenue requirement increase; thus, it is not dispositive that the proposed effective date is not prescribed by a contract. Finally, the Commission's regulations and precedent do not require that there be an "emergency" to find good cause for waiver.

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or before June 1, 2011, as discussed in the body of this order.

(E) Filing Parties are hereby directed to submit ongoing annual information reports, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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APPENDIX

INTERVENTIONS WITH SUBSTANTIVE COMMENTS

Acciona Wind Energy USA LLC (Acciona)
American Electric Power Service Corporation (AEP)[591]
Alliant Energy Corporate Services, Inc. (Alliant)
American Forest & Paper Association (AF&PA)
American Municipal Power, Inc. (AMP)
American Transmission Company LLC (ATC)[592]
American Wind Energy Association and Wind on the Wires (jointly, AWEA-WOW)
Association of Businesses Advocating Tariff Equity (ABATE)
Basin Electric Power Cooperative (Basin)
CPV Renewable Energy Company, LLC (CPV)
Designated PJM Parties[593]

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[591] AEP submitted the filing on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Southwest Electric Power Company, Public Service Company of Oklahoma, AEP Southwestern Transmission Company, Inc., and AEP Oklahoma Transmission Co., Inc.

[592] ATC submitted the filing with ATC Management, Inc.

[593] Designated PJM Parties include: Baltimore Gas and Electric Company (BG&E); Duquesne Light Company (Duquesne); Exelon Corporation (Exelon); Metropolitan Edison Company (MetEd), Pennsylvania Electric Company (Penelec) and Jersey Central Power & Light Company (JCPL); "collectively doing business as FirstEnergy"; PHI Companies (Pepco Holdings, Inc. and its affiliates Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company); Monongahela Power Company, The Potomac Edison Company and West Penn Power Company (collectively, Allegheny Power); Old Dominion Electric Cooperative (Old Dominion); PPL PJM Companies (PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; and Lower Mount Bethel Energy, LLC); Public Service Electric and Gas Company (PSEG); and UGI Utilities, Inc. (UGI).

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The Dayton Power and Light Company (DP&L)
Dominion[594]
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (Duke)
Edison Mission Energy (Edison Mission)
Electric Power Supply Association (EPSA)
E.ON Climate & Renewables North America LLC (E.ON)
Exelon
FirstEnergy Service Company (FirstEnergy)[595]
Fresh Energy[596] (filed comments only)
Gamesa Energy USA, LLC (Gamesa)
Hoosier Energy Rural Electric Cooperative, Inc. and Southern Illinois Power Cooperative (jointly, Hoosier-SIPC)
Iberdola Renewables, Inc. (Iberdola)
Illinois Commerce Commission (Illinois Commission)
Illinois Municipal Electric Agency (IMEA)
Indiana Office of Utility Consumer Counselor (Indiana OUCC)
Indianapolis Power & Light Company (IPL)
Indiana Utility Regulatory Commission (Indiana Commission)
Industrial Customers[597]
Integrys[598]

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[594] Dominion Resources Services, Inc. (DRSI) submitted the filing on behalf of Virginia Electric and Power Company (jointly, Dominion).

[595] FirstEnergy submitted the filing on behalf of The Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and The Toledo Edison Company, FirstEnergy Solutions Corporation, and American Transmission Systems, Inc. (ATSI).

[596] Fresh Energy includes: Center for Rural Affairs, Clean Wisconsin, Fresh Energy, Great Plains Institute, Iowa Environmental Council, Iowa Policy Project, Iowa Renewable Energy Association, Izaak Walton League of America, National Wildlife Federation, Natural Resources Defense Council, Ohio Environmental Council, Renew Wisconsin, Renew Missouri, and Union of Concerned Scientists.

[597] Industrial Customers include: Coalition of Midwest Transmission Customers (CMTC), Minnesota Large Industrial Group (Minnesota Industrials), Electricity Consumers Resource Council, Illinois Industrial Energy Consumers (Illinois Industrials), and Wisconsin Industrial Energy Group.

[598] Integrys includes: Wisconsin Public Service Corporation, Upper Peninsula Power Company, and Integrys Energy Services, Inc.

International Transmission Company (ITC), Michigan Electric Transmission Company, LLC (METC), ITC Midwest LLC (ITC Midwest), and Green Power Express (collectively, ITC Companies) and Wolverine Power Supply Cooperative, Inc. (Wolverine) (jointly, ITC Companies-Wolverine)
Iowa Utilities Board (Iowa Board)
Iowa Office of Consumer Advocate (Iowa Advocate)
Joint Protestors[599]
MISO Northeast Transmission Customers[600]
Michigan Citizens Against Rate Excess (MICH-CARE)
MPPA
Michigan Public Service Commission (Michigan Commission)
MidAmerican Energy Company (MidAmerican)
Midwest Generators[601]
Midwest TDUs[602]
Minnesota Public Utilities Commission (Minnesota Commission) and Minnesota Office of Energy Security (jointly, Minnesota Commission-Minnesota Security)
NextEra Energy Resources, LLC (NextEra)
Northern Indiana Public Service Company (NIPSCO)
Oak Creek Energy Systems, Inc. (Oak Creek)
Office of the Ohio Consumers' Counsel (OCC)
Organization of MISO States (OMS)[603]

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[599] Joint Protestors include: Dynegy Power Marketing, Inc., Dynegy Midwest Generation, Inc., DC Energy Midwest, LLC, Cargill Power Markets, LLC, and Westar Energy, Inc.

[600] MISO Northeast Transmission Customers include: Michigan Department of Attorney General (Michigan Attorney General), ABATE, Consumers Energy Company (Consumers Energy), The Detroit Edison Company, Michigan Municipal Electric Association (Michigan Municipals), and Michigan Public Power Agency (MPPA).

[601] Midwest Generators include: Invenergy Wind Development LLC, and Invenergy Thermal Development LLC (jointly, Invenergy), and Renewable Energy Systems Americas, Inc. (RES Americas).

[602] Midwest TDUs include: Madison Gas & Electric Company, Missouri Joint Municipal Electric Utility Commission, Midwest Municipal Transmission Group, Missouri River Energy Services (MRES), Prairie Power, Inc., and WPPI Energy (WPPI).

[603] OMS states that its comments are supported by the following OMS members: Indiana Commission, Iowa Board, Michigan Commission, Minnesota Commission, Missouri Public Service Commission (Missouri Commission), Montana Public Service

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PSEG Companies[604]
PJM Interconnection, LLC (PJM)
Southern Indiana Gas and Electric Company (Vectren South)
Southwestern Electric Cooperative, Inc. (Southwestern)
Senator Debbie Stabenow (Michigan Letter) (letter forwarding a constituent's comments)
Steel Producers[605]
SummitWind, LLC (SummitWind) (filed comments only)
Tenaska Power Services Co. (Tenaska)
Wisconsin Electric Power Company (Wisconsin Electric)
Public Service Commission of Wisconsin (Wisconsin Commission)
Wisconsin Industrials[606]
Xcel Energy Services, Inc. (Xcel)[607]

OTHER INTERVENTIONS

Allegheny Electric Cooperative, Inc.
Allegheny Power
ArcelorMittal USA Inc.
Baltimore Gas and Electric Company
Buckeye Power, Inc.
Calpine Corporation
CMTC
Consumers Energy
Dairyland Power Cooperative (Dairyland)
The Detroit Edison Company (Detroit Edison)

Commission (Montana Commission), North Dakota Public Service Commission (North Dakota Commission), South Dakota Public Utilities Commission (South Dakota Commission), and Wisconsin Public Service Commission (Wisconsin Commission).

[604] PSEG Companies include: PSEG, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[605] Steel Producers include: Nucor Steel-Indiana, Inc. and Steel Dynamics, Inc.

[606] Wisconsin Industrials include: Wisconsin Industrial Energy Group, Wisconsin Cast Metals Association, Midwest Food Processors Association and Wisconsin Paper Council.

[607] Xcel submitted the filing on behalf of Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) (jointly, Northern States).

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DRSI[608]
Duquesne Light Company
enXco Development Corporation (enXco)
FC Energy Finance I, Inc. and JPM Capital Corporation
Illinois Industrials
JPMorgan Ventures Energy Corporation and BE KJ LLC
LS Power Associates, LP
Maryland Public Service Commission
Michigan Attorney General
Michigan Municipals
Michigan South Central Power Agency (MSCPA)
Midland Cogeneration Venture Limited Partnership
Minnesota Industrials
Minnesota Municipal Power Agency
Minnkota Power Cooperative, Inc.
Missouri Commission
NRG Power Marketing, LLC
Old Dominion
Pennsylvania Public Utility Commission
PHI Companies
PPL PJM Companies
RRI Energy, Inc.

ANSWERS

EPSA (September 27, 2010)
ITC Companies (September 27, 2010)
MidAmerican (September 27, 2010)
MISO Northeast Transmission Customers (September 27, 2010)[609]
Hoosier-SIPC (September 27, 2010)
MidAmerican (October 8, 2010)
MISO Northeast Transmission Customers (October 12, 2010)
Midwest Independent Transmission System Operator, Inc. and Midwest ISO

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[608] DRSI filed a motion to intervene on behalf of Dominion Energy Kewaunee, Inc. and Dominion Energy Marketing, Inc.

[609] For the purposes of this filing, MISO Northeast Transmission Customers include Consumers Energy, Detroit Edison, Michigan Municipals and MMPA.

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Transmission Owners[610] (Filing Parties) (October 18, 2010)
MISO Northeast Transmission Customers (November 1, 2010)
MPPA and MSCPA (jointly, Michigan Agencies) (November 1, 2010)
AMP (November 2, 2010)
Designated PJM Parties (November 2, 2010)[611]
Duke (November 2, 2010)
E.ON (November 2, 2010)
Exelon (November 2, 2010)
FirstEnergy (November 2, 2010)
Iberdrola and Invenergy (jointly, Iberdrola-Invenergy) (November 2, 2010)
Integrys (November 2, 2010)
Midwest TDUs (November 2, 2010)
PSEG Companies (November 2, 2010)
RES Americas, Inc. (November 2, 2010)
AWEA-WOW (November 4, 2010 Answer)
AWEA-WOW (November 4, 2010 Attachments to Answer)
Dominion (November 5, 2010)[612]
enXco (November 8, 2010)
CMTC (November 8, 2010)
AMP (November 17, 2010)
MISO Northeast Transmission Customers (November 19, 2010)
AWEA-WOW (November 23, 2010 Amended Answer)
Illinois Commission (November 23, 2010 Answer)

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[610] For the purposes of this filing, Midwest Transmission Owners include: Ameren Services Co., as agent for Union Electric Co., Central Illinois Public Service Co., Central Illinois Light Co., and Illinois Power Co.; ATC; Dairyland; Great River Energy; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; NIPSCO; Northern States; Northwestern Wisconsin Electric Co.; Otter Tail Power Co.; and Southern Minnesota Municipal Power Agency.

[611] For the purposes of this filing, Designated PJM Parties include: BG&E; Duquesne; Exelon; MetEd, Penelec, and JCPL; "collectively doing business as FirstEnergy"; PHI Companies; Allegheny Power; Old Dominion; PSEG; and UGI.

[612] Dominion submitted the filing on behalf of Dominion Virginia Power.

Exhibit D

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EXHIBIT D

138 FERC ¶ 61,233
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER12-309-000

ORDER CONDITIONALLY ACCEPTING TARIFF REVISIONS

(Issued March 30, 2012)

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1. On November 1, 2011, as supplemented on January 30, 2012 and February 9, 2012, Midwest Independent Transmission System Operator, Inc. (MISO) submitted, under section 205 of the Federal Power Act (FPA),[1] proposed revisions to the Generator Interconnection Procedures (GIP) in Attachment X of its Open Access Transmission,

[1] 16 U.S.C. § 824d (2006).

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Energy and Operating Reserve Markets Tariff (Tariff) in order to address backlogs in its generator interconnection queue and late-stage terminations of generator interconnection agreements.

2. As discussed below, we will conditionally accept MISO's proposed revisions and make the Tariff revisions effective January 1, 2012, as requested.

I. Background

A. History of Interconnection Queue Issues

3. In Order No. 2003,[2] the Commission issued standardized large generator interconnection procedures (LGIP) and a standardized large generator interconnection agreement (LGIA). The Commission's goal was to minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.

4. In its compliance filing to Order No. 2003 and 2003-A, MISO stated that the geographic expanse of its footprint made it inefficient to process Interconnection Requests according to time of receipt, without regard for geography; thus, MISO proposed revisions to the *pro forma* LGIP in order to use a "group study" approach to queue processing. MISO also sought changes to the *pro forma* LGIP and LGIA that would permit MISO to study individual interconnection requests out-of-queue order based upon: (1) the electrical remoteness of the generating facility; or (2) the request of the interconnection customer, when MISO concurs with the request and has the resources to perform the study, and if the interconnection customer accepts the financial risk of restudy and reassignment of upgrades when the Interconnection Request become the next in the queue.[3]

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[2] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,027, at PP 122-123, *order on reh'g*, 109 FERC ¶ 61,085, at PP 25-28 (2004).

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5. The Commission accepted MISO's proposal to process interconnection requests in groups and out-of-queue order, as proposed, conditioned on MISO meeting timing requirements in Order Nos. 2003 and 2003-A.[4]

6. In 2008, the Commission held a technical conference regarding interconnection queuing practices and queue related issues that emerged after the issuance of Order No. 2003 and issued an order directing Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to develop and propose their own solutions to issues related to delays and backlogs in processing queues.[5]

7. To remedy this situation, MISO along with its stakeholders, created the Interconnection Practices Task Force to identify and correct the parts of its queue management procedures that were not functioning well. As a result of this stakeholder process, MISO proposed, and the Commission largely accepted, revisions to Attachment X of the Tariff in order to reform MISO's interconnection queue subject to annual informational reports.[6] These revisions modified MISO's GIP to limit delays caused by inactive projects in the queue. Among other things, MISO revised its procedure for processing interconnection applications from a "first-come, first-served" approach to an approach based on the progress that the generation project is making towards commercial operation, essentially a "first-ready, first-served" approach. Under these procedures, an interconnection customer pays the M1 study deposit to enter the Pre-Queue Phase. In this phase, a Feasibility Study is performed to determine whether the transmission system can accommodate the interconnection request and whether the project can move directly to the second phase of the queue – the Definitive Planning Phase – or whether it should proceed to the first phase of the queue – the System Planning and Analysis phase – for additional study.[7] If a project is not eligible to proceed to the Definitive Planning Phase, the customer then enters the System Planning and Analysis phase and undergoes a System Impact Study. After receiving its study results, the customer would then have to

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[4] *Id.*

[5] *Interconnection Queuing Practices*, 122 FERC ¶ 61,252, at PP 8-9 (2008) (Conference Order).

[6] *Midwest Indep. Transmission Sys. Operator, Inc.*, 124 FERC ¶ 61,183 (2008) (Queue Reform Order), *order on reh'g*, 127 FERC ¶ 61,294 (2009) (Queue Reform Rehearing Order).

[7] The System Planning and Analysis phase replaced the System Impact Study Phase in MISO's first queue reform proceeding.

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decide whether to fulfill the M2 milestone[8] in order to enter the Definitive Planning Phase. In the Definitive Planning Phase, the customer would receive a System Impact Study Review that would give them an approximation of the type and cost of upgrades that would have to be funded in order to facilitate their interconnection request. After receiving this information, the customer would then have to decide whether to fulfill the M3 milestones[9] in order to undergo a Facilities Study. Upon completion of the Facilities Study Review, the interconnection customer would then have the opportunity to negotiate an interconnection agreement. Under MISO's proposal, projects that had not yet started a Facilities Study were subject to all provisions of the new GIP; projects that had started a Facilities Study were only subject to revisions relating to suspension.

8. In 2009, MISO proposed, and the Commission accepted, additional revisions to its GIP that it characterized as its second phase of its interconnection queue reform.[10] MISO stated that its revisions were intended to address physical constraints that were delaying the interconnection of new generation in many areas of MISO's footprint and streamline the processing of interconnection requests. To address these concerns, MISO put in place two new *pro forma* agreements into the GIP: a facilities construction agreement for a single interconnection customer and a facilities construction agreement for multiple interconnection customers.

B. MISO's Proposal

9. MISO notes that delays associated with the failure of projects within the Definitive Planning Phase to move through that phase are causing backups. MISO states that it examined the queue in August 2011 to identify interconnection requests that were active on January 1, 2009 and are still active now. MISO states that this examination indicated that there were 141 interconnection requests, or just under half the queue, that met this criteria. MISO explains that 128 of these projects are located in Minnesota, Iowa, North Dakota, and South Dakota.[11] MISO believes that the primary factor causing this backup is the lack of renewable energy purchasers in the market. MISO asserts that

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[8] The M2 milestone refers to a set of requirements that an interconnection customer must meet before entering the Definitive Planning Phase. These requirements are discussed in further detail below.

[9] The M3 milestone refers to the requirements that an interconnection customer must meet in order to obtain a Facilities Study.

[10] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,301 (2009) (Queue Reform II).

[11] Mr. Eric Laverty Test. at 9 (Laverty Testimony).

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transmission uncertainty, particularly around Multi Value Projects (MVP),[12] creates a cost uncertainty for generators and makes it more difficult for generators to compete for the limited amount of demand in the market.[13] MISO claims that this lack of demand has made interconnection customers reluctant to meet the milestone between the System Impact Study and the Facilities Study in the Definitive Planning Phase or to complete a GIA. MISO states that it has also seen an increase in interconnection customers questioning study methods, challenging results, and using dispute resolution.[14]

10. MISO states that there has been a recent increase in the uncertainty surrounding whether an interconnection customer will have to be restudied due to the occurrence of an event identified as a contingency in its GIA.[15] MISO asserts that this uncertainty results from a recent increase in the number of projects with GIAs either terminating, breaching, or defaulting under their agreements. MISO explains that contingencies were less of an issue in 2008 when a low percentage of projects that executed a GIA withdrew their projects; in 2011, however, MISO states it has had between 10 and 20 projects with GIAs terminated, breached, or defaulted on their agreements.[16]

11. Also, MISO concedes that interconnection customers' concerns regarding study methods could be a result of mistakes made by MISO staff and that MISO takes these concerns seriously. MISO states that it was only after MISO saw the totality of the circumstances (i.e., similarities among the concerns, the reluctance of projects to move forward, and the lack of requests for proposals for new projects) that MISO determined that further queue reform was necessary.[17]

12. MISO explains that the reforms in this proceeding are intended to extend the idea of "first-ready, first-served" in the queuing process by removing timelines for

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[12] *Midwest Independent Transmission System Operator, Inc.* 133 FERC ¶ 61,221 (2010).

[13] Laverty Testimony at 9.

[14] *Id.* at 9-10.

[15] *Id.* at 9. *See also* MISO, FERC Electric Tariff, Attachment X (0.0.0), app. 6, art. 11.3 (providing for the restudy of a project if certain contingencies arise, including the withdrawal of a higher-queued customer, which may affect a project's responsibility for network upgrades).

[16] Laverty Testimony at 8-9.

[17] *Id.* at 11.

interconnection customers in order to allow them to proceed at their own pace.[18] MISO explains that, under its proposal, an interconnection customer will be permitted to remain in the System Planning and Analysis phase indefinitely, so long as the interconnection customer refreshes its study once every 18 months. MISO also explains that an interconnection customer may request to be studied using a variety of assumptions during the System Planning and Analysis phase. Under MISO's proposal an interconnection customer will have 30 days to complete and execute an interconnection study review form, which allows the interconnection customer to recommend changes to the model used to study its interconnection request. MISO further explains, however, that the result of studies performed in the System Planning and Analysis phase will *not* form the basis for interconnection studies performed in the Definitive Planning Phase.[19] Additionally, MISO explains that an interconnection customer may make changes to its interconnection request in the System Planning and Analysis phase.

13. At a time of its choosing, the customer may move to the Definitive Planning Phase by providing a study deposit, providing necessary information, and making a new M2 "cash-at-risk" payment.[20] Like in the System Planning and Analysis phase, under MISO's proposal, an interconnection customer will be required to complete and execute an interconnection study review form. Once in the Definitive Planning Phase, most modifications by the interconnection customer would be deemed to be Material Modifications.

14. Under MISO's proposal, an interconnection customer would be required to make an "initial payment" toward its network upgrade costs within a prescribed time period following the execution of its GIA or the filing of an unexecuted GIA with the Commission. In particular, the interconnection customer would be required to either pay a certain percentage of the total cost of its network upgrades or to provide security equal to 100 percent of the cost of network upgrades.[21] MISO states that this revision prevents

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[18] *Id.* at 8.

[19] Proposed revised section 7.3.

[20] The cash-at-risk payment entirely replaces all other means by which an interconnection customer can presently demonstrate readiness (e.g., ordering turbines). The cash-at-risk payment is generally based upon a formula that considers the $/MW year long-term firm point-to-point transmission service rate for the interconnecting zone in schedule 7, the MW size of the facility, and the number and cost of constraints.

[21] Under the currently effective *pro forma* GIA, an interconnection customer is required to provide security for the cost of its network upgrades 30 days prior to the commencement, design, procurement, installation, or construction of a discrete portion of

(continued…)

the customer from establishing a long lead time for a project without having to expend capital.

15. MISO proposes to apply its queue reform to certain existing interconnection requests. In particular, the revised GIP, including the M2 milestone payment, will apply to an interconnection customer that has an executed GIA but must be restudied due to, for example, a higher-queued interconnection customer withdrawing. The revised GIP will also apply where the interconnection customer is being studied for the first time and does not have an interconnection agreement. Such customers will be required by the end of a 90 day period following the effective date to transition to the new GIP.[22] Those projects that are unable to make the new M2 milestone payment would be placed in the System Planning and Analysis phase.[23] Only interconnection requests for projects that are in commercial operation and have an executed GIA as of the effective date of the revised GIP will be exempt from the revised GIP. However, MISO clarifies in its answer that it intends *not* to apply the M2 milestone payment to a customer with a signed GIA, that has not reached commercial operation (and is being restudied), where such customer has satisfied the milestones in its GIA.

16. Finally, MISO proposes a new sub-class of Energy Resource Interconnection Service called Net Zero Interconnection Service. This new service, states MISO, would allow an existing interconnection customer to increase the gross generating capability at the point of interconnection of an existing generating facility without increasing the net generation output at the point of interconnection above the existing generating facility's capacity, thereby permitting a new generating facility to interconnect at that point.[24] MISO states that the existing generator and a new generator would work out a means of controlling the output of the combined units. According to MISO, with the output

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certain network upgrades. MISO, FERC Electric Tariff, Attachment X (0.0.0), app. 6, art. 11.5.

[22] Proposed revised sections 5.1.1.2, 5.1.2 and 8.2.

[23] Proposed revised section 5.1.1.

[24] According to MISO, the terms and conditions of Net Zero Interconnection Service will be governed by an Energy Displacement Agreement and a Monitoring and Consent Agreement. Under MISO's proposal, an interconnection customer seeking Net Zero Interconnection Service will be required to enter into an Energy Displacement Agreement with the owner of the existing generating facility prior to submitting a request for net zero service if the customer is not the owner or subsidiary of the existing generator.

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controlled, the net effect on output seen by the system is unchanged, thus the name "net zero."

II. Notice and Responsive Pleadings

17. Notice of the November 1 Filing was published in the *Federal Register*, 76 Fed. Reg. 69,716 (2011), with interventions or protests due on or before November 30, 2011.[25]

18. On December 30, 2011, staff issued a letter informing MISO that the November 1 Filing was deficient and requesting additional information. MISO submitted a response to this letter on January 30, 2012 (Supplemental Filing).

19. Notice of MISO's January 30 Response was published in the *Federal Register*, 77 Fed. Reg. 6103 (2012), with interventions or protests due on or before February 21, 2012.

20. The entities listed in Appendix A filed motions to intervene, including EDP, Prairie Rose, and Akuo, who filed motions to intervene out of time.

21. Intervenors who also submitted comments supporting MISO's proposed revisions include MISO Transmission Owners, Xcel, Alliant, and Midwest TDUs.

22. Intervenors who protested or commented adversely on aspects of MISO's proposed revisions include EcoEnergy, NextEra, Geronimo, National Renewable Solutions, AMP, Iberdrola, the Midwest Developers, AWEA and WOW, E.ON, Flat Hill, EPSA, Detroit Edison, Joint Protestors, Juhl, and Calpine. American Renewable Energy Solutions, LLC (ARES) filed comments but did not move to intervene.

23. Answers were filed by Prairie Rose, the Joint Protestors, Xcel, MISO, the Midwest Developers, and the MISO Transmission Owners.

24. On January 31, 2012, Prairie Rose filed a motion asking the Commission to separate its consideration of Net Zero Interconnection Service from the other issues in

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[25] On November 3, 2011, the AWEA and WOW filed a motion asking the Commission to extend the time to file comments to December 6, 2011. On November 8, 2011, the Commission issued a notice extending the time to file comments, protests, and interventions to November 29, 2011. On November 15, 2011, WOW filed an additional motion asking the Commission to extend the time for submitting comments, protests, and interventions to December 2, 2011, and E.ON Climate & Renewables North America LLC (E.ON) subsequently filed a motion supporting WOW's motion. On November 18, 2011, the Commission issued a notice extending the date for filing comments, protests, and interventions to November 30, 2011.

this docket and to expeditiously approve Net Zero Interconnection Service within 30 days of its motion. Joint Protestors filed an answer opposing Prairie Rose's motion.

III. Discussion

A. Procedural Matters

25. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

26. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2011), the Commission will grant EDP's, Prairie Rose's, and Akuo's late-filed motions to intervene given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay. We will also accept the late protests of Juhl and ARES given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

27. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We will accept the answers that have been filed in this proceeding because they have provided information that assisted us in our decision-making process.

B. Standard of Review

28. The Commission applies an independent entity standard to evaluate RTOs and ISOs proposals for revisions to the procedures outlined in Order No. 2003.[26] Under that standard, independent entities, such as RTOs and ISOs, are entitled to more flexibility in proposing variations than are non-independent entities, primarily because they do not have affiliated generation and thus are less likely than non-independent entities to favor one generator over another. Under the independent entity standard, MISO must demonstrate that its proposed variations are just and reasonable and not unduly discriminatory, and that they would accomplish the purposes of Order No. 2003.[27]

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[26] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822-827; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 759. *See also* Queue Reform Order, 124 FERC ¶ 61,183 at P 31; Conference Order, 122 FERC ¶ 61,252 at P 13.

[27] Conference Order, 122 FERC ¶ 61,252 at P 13, n.10.

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C. Substantive Matters

29. We believe that, as modified below, the proposed revisions to the GIP are just and reasonable and build upon previous queue reform efforts in an attempt to further the goals of Order No. 2003: to minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.

30. In previous phases of queue reform, MISO has implemented reforms designed to expedite the processing of the queue, such as embracing a "first-ready, first-served" approach, modifying milestones that an interconnection customer must meet in order to proceed through the interconnection queue, and adopting limitations on the ability of projects to suspend. As discussed further below, the evidence provided in this proceeding indicates that, while progress has been made, further reform is necessary due to the fact that MISO continues to experience a backlog in the queue and has seen an increase in the number of projects withdrawing in the later stages of the interconnection process. We believe that, as modified below, MISO's proposed revisions to the GIP, including the adoption of enhanced financial milestones, removing timelines for customers to proceed to the Definitive Planning Phase, and requiring interconnection customers to sign-off on study models will help achieve the overall goals of interconnection queue reform – discouraging speculative or unviable projects from entering the queue, getting projects that are not making progress toward commercial operation out of the queue, and helping viable projects achieve commercial operation as soon as possible.[28] We also find that MISO's proposal to implement Net Zero Interconnection Service, as modified below, has the potential to foster the efficient use of the transmission system. Therefore, as discussed below, we conditionally accept MISO's proposal under the independent entity standard, subject to MISO making a compliance filing.

1. Need for Reform

a. Comments

31. Several commenters argue that MISO's proposal is premature and that the backlog identified by MISO results from the ongoing study of the so-called Group 5 projects[29] as

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[28] Queue Reform Order, 124 FERC ¶ 61,183 at P 44.

[29] The Group 5 projects consist of interconnection requests in Southwest Minnesota, Northwest Iowa, and Eastern South Dakota. MISO's GIP in Attachment X provides that generator interconnection projects may be studied as a group for the purpose of conducting interconnection studies. MISO conducted the generator interconnection system impact studies as a group for the Group 5 projects. The initial

(continued…)

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well as the fact that the MVP projects have not yet gone into effect.[30] The Midwest Developers, AWEA, and WOW argue that the delay in studying the Group 5 projects, due to errors on the part of MISO and changes within Group 5, has resulted in a backlog of interconnection customers and has stalled other study groups within the western portion of MISO's footprint.[31] The Midwest Developers state that they expect that the restudies of the Group 5 projects should be completed in the first quarter of 2012, with the negotiation and execution of interconnection agreements to occur in the second and third quarters of 2012.[32] The Midwest Developers, AWEA, and WOW state that they expect that MISO's approval of its first set of MVPs, hopefully including upgrades that will allow the Group 5 projects to proceed, will reduce uncertainty and alleviate congestion in the queue.[33] The Midwest Developers add that the fact that the vast majority of the congestion is located in the western part of its footprint demonstrates that congestion in the queue is not the result of any flaws in the existing interconnection procedures as much as it is the result of unique factors in that region.[34] They further state that the existing queue procedures should be given time to work and that further reforms should only be considered after the issues driving the backlog in the queue are resolved.[35] Iberdrola argues that "[w]hile MISO's contentions regarding the supply and demand balance may be true, timely completing studies, and moving forward on transmission

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studies were performed in 2006 and 2007 and the study reports were posted during the summer and fall of 2007. In late 2009, MISO indicated that restudy of the Group 5 projects was necessary due to the withdrawal of higher-queued generators, including some members of Group 5. *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,165, at P 28 (2010).

[30] Midwest Developers Protest at 2-4; AWEA and WOW Protest at 6-7; NextEra Protest at 2; Iberdrola Protest at 16-17.

[31] Midwest Developers Protest at 2-3, 8-10; AWEA and WOW Protest at 6.

[32] Midwest Developers Protest at 11.

[33] *Id.* at 10-11; *see also* AWEA and WOW Protest at 6-7.

[34] Midwest Developers Protest at 9.

[35] Midwest Developers Protest at 8; AWEA and WOW Protest at 7. *See also* NextEra Protest at 2-3.

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projects that affect network upgrade costs and access to the market is the more appropriate path to increase certainty."[36]

32. AWEA and WOW state that, while MISO's proposed revisions may make the interconnection process more efficient for MISO, they will result in an ineffective process for interconnection customers and will result in a burdensome and unnecessary queue clearing exercise that will create significant new barriers to entry for new generators.[37] The Midwest Developers similarly contend that MISO's proposed revisions will lead to further uncertainty and unfairness for interconnection customers.[38]

33. The Midwest Developers contend that MISO's proposal is not entitled to the deference that is typically given to proposals that are vetted through the stakeholder process. They state that MISO's proposal is largely barren of stakeholder input; MISO did not even hold a vote on its final proposal and instead chose to revise the generation procedures over the objections of affected stakeholders.[39] Iberdrola notes that very few substantive changes were made to MISO's original proposal based on feedback it received through the stakeholder process, and that while stakeholder recommendations are advisory, it is an important opportunity for MISO to explain its rationale and address issues raised by stakeholders to avoid unintended consequences. Iberdrola states that the Commission should not afford deference to MISO's proposal.[40]

34. Accordingly, the Midwest Developers, AWEA and WOW, and Iberdrola ask that the Commission reject MISO's proposal in its entirety with the exception of MISO's proposal to implement Net Zero Interconnection Service. The Midwest Developers argue that, if the Commission decides that the scheduled completion of the Group 5 study process and the implementation of the MVP process, together with its existing queue procedures, might warrant additional scrutiny, the Commission should direct MISO to submit quarterly reports thereby apprising the Commission and stakeholders of its progress in implementing the MVP procedures and clearing out the Group 5 projects.[41]

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[36] Iberdrola Protest at 4.

[37] AWEA and WOW Protest at 8.

[38] Midwest Developers Protest at 4-5.

[39] *Id.* at 13-14.

[40] Iberdrola Protest at 18.

[41] Midwest Developers Protest at 14.

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Likewise, AWEA and WOW state that, if the Commission determines that changes might be needed to the queue in the future, it could direct MISO to submit quarterly informational filings for the next calendar year.[42]

35. A number of parties express support for MISO's proposals.[43] Alliant notes that MISO's latest effort to reform its queue has been ongoing for a year and that MISO actively engaged with stakeholders prior to proposing revisions, which resulted in several changes to MISO's proposals. Alliant states that it believes that MISO's proposal will substantially improve the queue and strikes a fair balance with all parties that need to use the queue. While acknowledging that MISO's proposals may result in projects withdrawing from the queue and deter other projects from entering the queue, it maintains that these consequences are necessary in order to address the current backlog issues and to prevent these issues from reoccurring. Alliant adds that the urgency of making improvements has been heightened due to the Environmental Protection Agency's Cross State Air Pollution Rule and other regulations, which will result in the retirement of a substantial amount of existing generation.[44]

b. <u>Answers</u>

36. In its answer, MISO argues that the testimony of Mr. Eric Laverty, which it submitted in the November 1 Filing, demonstrates that there is an excessive buildup of projects in the Definitive Planning Phase, which is the result of inefficiencies caused by the use of timelines for customers to proceed through the interconnection process.[45] According to MISO, Mr. Laverty's testimony indicated that its previous phases of queue reform have not been as successful in eliminating the backlog in the queue to the extent that MISO hoped in those areas with a high density of interconnection as it has in areas with fewer interconnection requests. MISO explains that, as of December 1, 2011, out of the approximately 32 gigawatts (GW) of projects in the interconnection queue, there were approximately 25 GW of projects in the queue that were at or beyond the Definitive Planning Phase but that had not executed a GIA. MISO maintains that this pattern indicates that a number of projects that enter the Definitive Planning Phase are not ready to proceed and simply wait there while they attempt to resolve uncertainties or obtain

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[42] AWEA and WOW Protest at 5.

[43] Midwest TDUs Comments at 3; MISO Transmission Owners Comments at 2-3; Alliant Comments at 3.

[44] Alliant Comments at 3-4.

[45] MISO December 15 Answer at 4.

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financing. MISO adds that approximately 15 percent of the total projects that met the M2 milestone[46] between 2009 and today have subsequently dropped out of the Definitive Planning Phase.[47] MISO explains that 28 projects that met the M2 Milestone subsequently dropped out of the queue in 2011. MISO further explains that these 28 projects are in addition to 12 projects that dropped out in 2009 and 2010.[48] MISO further maintains that even execution of a GIA has not been a sufficient indicator of readiness, as at least 12 projects with executed GIAs in place terminated their agreements in 2011 and several other projects breached their agreements.[49] MISO, therefore, argues that its proposed revisions are necessary to enhance certainty by ensuring that those customers that enter the Definitive Planning Phase are ready to proceed towards commercial operation.[50]

37. Additionally, MISO rejects the notion that the root cause of the queue delay is ongoing commercial uncertainty about the cost responsibility of the Group 5 projects. MISO states that, even after MISO evaluates its first round of MVP projects, the Group 5 projects will still be responsible for approximately $300 million in upgrades before these projects can interconnect. Accordingly, MISO states that it is unlikely that these projects will do so quickly; in fact, MISO states that it is likely that some of these projects will drop out and that these withdrawals will spur further withdrawals from the Definitive Planning Phase.[51]

38. In its answer to MISO's answer, the Midwest Developers argue that MISO has failed to establish any causal link between decisions made by interconnection customers and the queue backlog that would justify its sweeping proposal. The Midwest Developers argue that the 15 percent drop out rate identified by MISO actually appears

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[46] The currently effective M2 milestone consists of three different elements. The first element is a study deposit based upon the size of the proposed interconnection. The second element requires the customer to provide detailed technical data (*e.g.*, point of interconnection, one-line diagrams, etc.) to MISO. The third element requires the customer to meet two out of six indicia of readiness.

[47] MISO December 15 Answer at 4-5.

[48] *Id.*

[49] *Id.* at 5-6.

[50] *Id.* at 7-10.

[51] *Id.* at 6 n.12.

quite reasonable and does not support the proposal to fundamentally overhaul its queue procedures.[52] They claim that the fact that the drop-out rate is fairly low is illustrative of developers' commitment to their projects in the queue, especially in light of the fact that many of these developers have been stuck in the queue for years without any material progress. In this regard, they note that MISO recently announced that some Group 5 Facilities Studies and the Definitive Planning Phase Cycle 1[53] System Impact Study would be further delayed. They state that MISO's assertions regarding the cost responsibility for the Group 5 projects actually demonstrates that MISO's proposed revisions will not address the actual problem. They claim that MISO's proposals will simply force the Group 5 projects to either pay large amounts of likely nonrefundable deposits to learn what portion of the $300 million would be allocated to them or get out of the queue, which will cause costs to shift to other generators if projects drop out. They state that the resulting process would undermine the ability of customers to determine whether their project is ready to proceed and imposes greater risk on customers.[54]

c. Supplemental Filing

39. MISO explains that it came to the conclusion that the primary factor driving the back-up in the queue is a mismatch between supply and demand based upon two forward looking forecasts and one backward looking assessment of wind data. First, MISO reviewed the Department of Energy's list of current requests for proposals for renewable energy, which show that not more than 250 MW of wind has been requested in MISO's footprint at any one time over the last year. Second, MISO points to its findings in its monthly Informational Forum presentations which include a comparison of the wind output over the last 12 months to the wind output necessary to meet the state renewable portfolio standards (RPS). MISO asserts that with the RPS requirements to purchase renewable energy already met, the market for such energy is more limited.[55]

40. Third, MISO reviewed the work performed under the Regional Generator Outlet Study and looked at the nameplate installations required to meet those same state RPS

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[52] Midwest Developers December 20 Answer at 3 (noting that the drop-out rate in the footprints of other ISOs and RTOs can be significantly higher).

[53] *See generally* Supplemental Filing at 5. Group 5 is the first of 10 queued group studies in the west region of MISO. The subsequent west region group studies are referred to as Definitive Planning Phase Cycles 1 through 9.

[54] Midwest Developers December 20 Answer at 3-5.

[55] Supplemental Filing at 2-3.

requirements. MISO notes that this review involved a 2009-vintage load forecast and maintains that the lingering effects of the recession are ignored in that work. Based on this review, MISO determined that the currently installed wind capacity, plus the amount that was then scheduled to be installed through 2011 was already sufficient to meet the 2014-2015 level of wind capacity necessary to meet the RPS requirements in the MISO footprint.[56]

41. MISO followed up on its third approach at the March 2011 meeting of its Interconnection Process Task Force. At that time, the review demonstrated a slight narrowing of the gap between the amount of renewable energy needed to meet RPS requirement and the renewable energy capacity in MISO (sufficient to meet 2013-2014 standards, rather than 2014-2015, still using 2009 load forecasts). However, this analysis still showed that renewable energy capacity in MISO was ahead of the amount needed to meet state RPS requirements based on a comparison of that graph of RPS needs with the wind projects in various stages of the queue at that time.

42. With respect to the Group 5 projects, MISO states that the System Impact Study has been completed and that facilities studies are due to be completed by the first week in February 2012 with the negotiation of GIAs, facilities construction agreements, and multi-party facilities construction agreements following those studies. MISO asserts that the delay in the commencement of facilities studies was caused by the disagreement between MISO and several interconnection customers with respect to the M3 milestones in the current process and the logistical step of obtaining proposals from multiple consultants to perform the facilities studies and then collecting the study deposits from the interconnection customers.[57] Interconnection customers now have initial estimates of their costs to interconnect, and are merely waiting on those cost estimates to be further refined in the Facilities Study phase. MISO states that as described above and in the Midwest Developers answer to MISO's answer, what interconnection customers do not know is what their anticipated revenue from a power purchase agreement will be.[58] Accordingly, states MISO, it is difficult for them to determine whether it is economical for them to fund the upgrades needed to interconnect their projects.

43. MISO further notes that Group 5 is the first of 10 study groups currently in the western region of MISO. MISO observes that two projects within Group 5 have withdrawn from the MISO queue and that while the withdrawal of these two projects alone will not cause a restudy, additional projects dropping out would likely trigger the

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[56] *Id.* at 3.

[57] *Id.* at 4 (footnote omitted).

[58] *Id.* at 3 (citing Midwest Developers December 20 Answer at 6-7).

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need for yet another restudy for Group 5 and cause cascading restudies in all subsequent West region group studies in Definitive Planning Phase Cycles 1-9.

44. MISO states that, while the Group 5 projects are currently garnering attention, the issues identified by MISO go beyond the group. MISO cites to the Definitive Planning Phase Cycle 5 group study in North Dakota with seven projects. MISO states that before GIA negotiations had even started, one project dropped out, which led MISO to start negotiations with six projects that involved six GIAs and three multi-party facilities construction agreements. The process of withdrawals continued such that only two projects remain, requiring a GIA and only one facilities construction agreement. MISO further explains that Project G622 recently withdrew during negotiations, which has triggered a restudy of Definitive Planning Phase Cycle 5 in North Dakota to determine if the remaining facilities construction agreement and network upgrades are needed. MISO also explains that this restudy will very likely cause a second restudy of the Definitive Planning Phase Cycle 6 study in North Dakota. MISO states that the number of iterations due to projects dropping out of the queue because they are not ready to proceed has prolonged the study process and such "queue churn" is preventing the "ready" projects from moving forward in an expeditious manner.[59]

45. MISO notes that it considered alternatives to its proposed revisions to the GIP to address the current backlog in the queue. MISO explains, for instance, that it considered a "non-queue" approach, which would have led to a complete separation of an interconnection queue position from the cost of interconnection. MISO states that, after considering feedback from stakeholders, it determined that this approach would not be achievable for a number of years and that the higher priority was to revise the queue to more quickly resolve the glut of capacity at the front of the queue.[60]

46. Finally, in response to a staff deficiency letter asking questions concerning the status of projects in the queue, MISO provided a table containing the total number of interconnection requests in the following five categories: (1) those in the queue; (2) those in the System Planning and Analysis phase; (3) those with executed GIAs that have not commenced commercial operation that are expected to be restudied; (4) those that are currently in suspension; (5) those in the Group 5 study group; and (6) those that are contingent on the Group 5 projects.[61]

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[59] Supplemental Filing at 4 (footnote omitted).

[60] *Id.* at 5.

[61] *Id.* at 6.

d. Comments on the Supplemental Filing

47. Iberdrola maintains that the Commission should reject MISO's filing in its entirety, with the exception of the Net Zero Interconnection Service proposal, without prejudice. Iberdrola acknowledges that MISO continues to experience issues in its interconnection queue. However, according to Iberdrola, MISO has neither provided evidence supporting the urgency of its proposal nor justified its draconian queue clearing proposal. Iberdrola notes that nearly half of the interconnection requests that MISO identified in its Supplemental Filing are either contingent upon or included in the Group 5 projects. Iberdrola further notes that these interconnection requests will, by necessity, be provisional because they are dependent on construction of a subset of MVP transmission lines. As a result, according to Iberdrola, MISO has time to develop a reasoned solution with stakeholder consensus that addresses the complex issues that are actually hindering the processing of the queue.[62]

48. Iberdrola states that MISO must develop long-term solutions that are consistent with its role as an independent entity. Iberdrola notes that the "non-queue" option would have provided an opportunity to discuss the causes of MISO's current GIP problems, if not an actual solution, and that it would have preferred that option over the current queue-clearing exercise.

49. Iberdrola states that MISO's justification for the proposed reforms is based on inherently discriminatory assumptions. Iberdrola argues that MISO makes little attempt to hide the fact that its proposed modifications to the GIP were targeted at wind generators. Iberdrola argues that MISO's proffered justification is based on an incorrect assumption about the link between RPS requirements and energy demand, as nothing limits a market participant from purchasing energy from renewable resources beyond its RPS requirements. Iberdrola maintains that MISO is attempting to predetermine market outcomes by assuming a fundamental market bifurcation between renewable energy and non-renewable energy, which is contrary to the purpose of an ISO.[63]

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[62] Iberdrola February 21 Protest at 1-2.

[63] *Id*. at 6 (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (stating that "[t]he fundamental purpose of an ISO is to operate the transmission systems of public utilities in

(continued…)

50. Moreover, Iberdrola argues that MISO's Supplemental Filing makes it clear that MISO is unwilling to address the more complex problems of queue processing in a competitive market. Iberdrola states that, despite MISO's assertions to the contrary, MISO's proposal lacked broad based support and that real solutions need to address the complexity of transmission planning and acknowledge MISO's responsibility. According to Iberdrola, MISO has made no attempt to dispel the conclusion that its proposed revisions are intended to clear the queue to ease pressure on MISO by shifting the majority of risks and responsibility to interconnection customers through higher barriers to entry and limiting the ability to challenge the process. While Iberdrola concedes that it may be the case that interconnection customers are delaying the process because they don't have revenue risk, it is part of the process as MISO cannot provide clear cost estimates until it completes its studies.[64]

51. Accordingly, Iberdrola maintains that the Commission should reject MISO's proposed reforms and direct it to propose a more comprehensive set of reforms developed through a robust stakeholder process.[65] Iberdrola further claims that the Commission should reiterate to MISO that any reforms must share responsibilities between the interconnection customer and MISO.[66]

52. E.ON states that the data provided by MISO in response to the staff deficiency letter demonstrates that there is no systemic queue backlog resulting from interconnection customers' decisions and actions. E.ON states that this data shows that an overwhelming majority of interconnection requests in the Definitive Planning Phase – 92 out of the 123 requests in the Definitive Planning Phase (75 percent) – are contingent upon the Group 5 projects. This, E.ON concludes, demonstrates that a vast majority of the projects have been languishing in the queue as a result of the ongoing study of the Group 5 projects, not customer inaction. While E.ON acknowledges that the data provided by MISO shows that one-third of all interconnection requests in the queue have progressed to the last stage before a GIA is executed, E.ON states that no further conclusions can be drawn from this data and that it certainly does not demonstrate that customers are impeding the progress of projects through the queue. Moreover, E.ON identifies several questions that it believes that MISO's response does not address, including how many of

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a manner that is independent of any business interest in sales or purchases of electric power by those utilities")).

[64] *Id.* at 7-8.

[65] *Id.* at 3-4.

[66] *Id.* at 9-10.

the projects in the Definitive Planning Phase have been subjected to restudy due to the occurrence of an event identified as a contingency or due to errors in an earlier study.[67]

53. E.ON also notes that MISO's data shows that 81 out of the 364 requests in the MISO queue have moved out of the Definitive Planning Phase and have an executed GIA. E.ON states that this is significant, as these projects represent over 12,000 MW, and shows that interconnection customers are executing GIAs as required by the current GIP process. E.ON further states that the fact that only three of the 81 requests are in Group 5 is telling, as it shows that, even with the delays of the Group 5 restudy, the queue in other sub-regions of MISO has been moving forward nicely and as expected. Moreover, E.ON explains that the fact that these projects have not achieved commercial operation is not significant because commercial operation is driven by, among other things, when the interconnecting transmission owner can complete the required network upgrades.[68]

54. Additionally, E.ON observes that there are only 6 interconnection requests with an executed GIA (only 7.4 percent of those projects with an executed GIA) that are expected to be restudied prior to commercial operation. E.ON argues that seven percent is not illustrative of a systemic MISO-wide problem and certainly does not demonstrate a significant "queue churn" problem as MISO alleges. On the contrary, E.ON claims that this data shows that 93 percent of the projects with an executed GIA will not be subjected to restudy or "queue churn," which means that the vast majority of projects that are lower in the queue will not be subject to queue churn. E.ON maintains that these data show that the GIP process is working as designed to move projects toward interconnection and commercial operation.[69]

55. With respect to suspension, E.ON notes that Mr. Laverty's testimony in the November 1 Filing suggests that a significant number of projects have moved into suspension and that, on this basis, MISO is proposing to impose higher financial milestones earlier in the interconnection process. E.ON argues that the data contained in the Supplemental Filing belie Mr. Laverty's assertion because they show that only 9 out of the 364 projects in the queue (2.4 percent) have initiated suspension – hardly demonstrating that there is a queue-wide problem requiring sweeping revision of the queue. E.ON further argues that, given the fact that suspension is only available for force

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[67] E.ON February 21 Protest at 2-3.

[68] *Id.* at 3-4.

[69] *Id.* at 4.

majeure, even if suspension were causing "queue churn," it would be due to forces beyond the control of interconnection customers.[70]

56. E.ON states that the only thing missing in the assessment of the factors causing the backlog is an examination of MISO itself. E.ON asks the Commission to exercise its authority under the FPA to require fast and accurate study results, partial refunds for late results, and greater finality of results, thereby minimizing restudies and delays. Similarly, E.ON argues that the Commission should order MISO to amend its tariff to provide that MISO will provide all costs that must be in an interconnection agreement according to the timing requirements listed in the particular and applicable phase (i.e., System Planning and Analysis phase or Definitive Planning Phase).[71] Additionally, Additionally, E.ON recommends the Commission institute monetary penalties if MISO misses study deadlines.

57. The Joint Protestors reject the idea that the problems in the queue result from a supply-demand imbalance and instead claim that the problem is MISO's administration of the queue. They note that while the current economic situation exists throughout the United States, MISO is the only transmission provider that alleges the need to eliminate the queue and implement drastic reforms. The Joint Protestors state that while MISO is correct in stating that it is difficult to determine whether it is economical for them to fund the upgrades needed to interconnect a project without a power purchase agreement, MISO's proposed changes will not solve that problem.[72]

58. The Joint Protestors state that the first step in promoting certainty, speed, and predictability is to have a study process based upon a consistent model instead of the discriminatory practice of allowing study assumptions to vary for incumbent utility projects. According to the Joint Protestors, until there is a benchmark model created by an independent set of engineers and that model is applied uniformly, it would be reasonable to assume that disputes will continue to arise.[73]

59. AWEA and WOW argue that the Commission should reject MISO's proposal because MISO failed to respond to all of the questions posed in the deficiency letter. In particular, AWEA and WOW argue that MISO failed to explain how MISO had come to the conclusion that the primary factor driving the backlog in the queue is the lack of

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[70] *Id.* at 5.

[71] *Id.* at 7-8.

[72] Joint Protestors February 21 Protest at 4-5.

[73] *Id.* at 5-6.

renewable energy purchasers in the market because MISO fails to demonstrate how this supposed lack of demand is causing the backlog in the queue. Additionally, AWEA and WOW state that MISO failed to respond to the question about whether it believes that the Group 5 restudies are impacting the backlog and failed to discuss the degree to which the queue issues would be resolved if the Group 5 studies were complete, merely providing an update about the status of those studies.[74]

60. AWEA and WOW also argue that MISO misunderstands the market for wind power and the development process for new generators and, as a result, has unrealistic expectations of the interconnection process. They state that MISO's Supplemental Filing suggests that MISO believes that it understands how many MWs of wind projects will make it through the interconnection process and that it can predict or influence the amount of generation that should be developed in the region. They claim that MISO incorrectly assumes that the driver for wind development is state RPS requirements and that utilities' requests for proposals are the only way to participate in that market. They explain that developers are building projects based on a variety of commercial strategies and that there are buyers that purchase wind power even if not compelled to do so. AWEA and WOW further assert that, while MISO mistakenly assumes that withdrawals will not occur in a well-functioning queue, this is unrealistic and does not take into account the fact that the interconnection queue is intended to provide information to developers that is necessary to make informed decisions about whether to continue.[75]

e. <u>Answers</u>

61. In its answer, MISO emphasizes that it believes that its proposal will provide more certainty of upgrade costs by permitting projects to obtain additional information while remaining in the queue.[76] MISO rejects the contention that the proposal disproportionately impacts wind projects. MISO explains that proposed wind accounts for approximately 85 to 90 percent of the capacity in the MISO queue. Thus, according to MISO, it is not surprising that the queue reforms impact many wind projects.[77]

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[74] AWEA and WOW February 21 Protest at 3-5.

[75] *Id.* at 5-7.

[76] MISO March 7 Answer at 9-11.

[77] *Id.* at 11-12.

f. Commission Determination

62. Based on the evidence provided by MISO, it appears that MISO is experiencing several challenges in administering its queue. We believe that such evidence justifies MISO's proposed tariff changes, subject to certain conditions established further below.

63. First, the evidence supports a finding that MISO continues to experience a substantial backlog in the Definitive Planning Phase of its queue. According to MISO, as of December 1, 2011, there were approximately 32 GW worth of projects in the queue. Out of these 32 GW, MISO explains that there were 25 GW of projects that were at or beyond entry into the Definitive Planning Phase but had not executed a GIA.[78] The data provided by MISO in the Supplemental Filing further supports MISO's assertion that it is currently experiencing a backlog in the queue, with many interconnection requests in the Definitive Planning Phase.[79] In addition, it appears that 141 interconnection requests have been in the queue for over three years – 128 of which lie in Minnesota, Iowa, North Dakota and South Dakota.[80]

64. Second, we agree with MISO that the existing M2 milestones are not sufficient for distinguishing between projects that are likely to achieve commercial operation and those that are not. The evidence demonstrates that "queue churn" continues to be a significant problem in MISO.[81] According to MISO, it has seen a recent increase in the number of projects withdrawing from the queue: 28 projects that met the M2 Milestone subsequently dropped out of the queue in 2011. These projects are in addition to 12 projects that dropped out in 2009 and 2010. MISO states that these terminations amount to a drop-out rate of 15 percent of the total projects that met the M2 Milestone between 2009 and present day.[82] Further, MISO states that terminations have resulted in multiple and iterative restudies and a corresponding increase in uncertainty for lower-queued customers.[83] We believe that requiring interconnection customers to put more money at

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[78] MISO December 15 Answer at 4.

[79] *See, e.g.*, Supplemental Filing at 6 (showing 123 interconnection requests currently in the Definitive Planning Phase).

[80] Laverty Testimony at 9.

[81] The Commission has previously recognized the importance of eliminating "queue churn." *See, e.g.*, Queue Reform Order, 124 FERC ¶ 61,183 at P 59.

[82] MISO December 15 Answer at 5.

[83] Laverty Testimony at 8-9; Supplemental Filing at 3-4.

risk, earlier in the interconnection process, will help ensure that projects that do advance through the DPP will be more likely to reach commercial operation.

65. These commenters identify alternative explanations for why the issues identified by MISO exist, such as the ongoing restudy of the Group 5 projects, or identify developments that they believe will alleviate this backlog, such as the construction of the first set of MVP projects, and urge us to reject MISO's proposed reforms on this basis. They also argue that the "queue churn" problem identified by MISO does not exist or is not as severe as MISO alleges, as the drop-out rates in the footprints of other ISOs and RTOs are higher than the dropout rate in MISO and, based on data provided by MISO, the number of projects subject to restudy is low.

66. Nonetheless, we find that MISO has provided sufficient evidence to support its justification for its proposed tariff changes discussed herein. We have evaluated the potential cause(s) of the backlog in the Definitive Planning Phase described by MISO and interconnection customers, and find that it is likely that *all* of these causes contribute in some way to the backlog. At present there is a significant mismatch in power projects competing for purchase power agreements that are available through RPS mandates. For example, materials referenced by MISO in its Supplemental Filing[84] indicate that in December 2011, MISO's regional RPS energy target was just over 1,000 GWh, while commercially operational generators in MISO produced 2,771 GWh of renewable energy. While purchase power agreements arising from RPS mandates are not the only opportunity for power developers, we understand from MISO's testimony that interconnection customers are increasingly questioning study outcomes, which in turns contributes to the backlog in the Definitive Planning Phase. Finally, while these reforms will not solve the problem of a general lack of power purchase agreements or that there is more renewable energy available then MISO-wide RPS energy targets require, we note that MISO's proposal is consistent with the overall goals of interconnection queue reform – discouraging speculative or unviable projects from entering the queue, getting projects that are not making progress towards commercial operation out of the queue, and helping viable projects achieve commercial operation as soon as possible.[85].

67. Clearly, there is also uncertainty for lower-queued interconnection customers due to cost responsibility not being resolved for Group 5. We understand from MISO that the facility study report on Group 5 will be issued this year. We also understand that while MVPs recently approved by the MISO Board of Directors will benefit Group 5, additional cost responsibility remains to be allocated among Group 5 members.[86] In addition, Group 5 is not the only group study creating uncertainty.

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[84] Supplemental Filing at 2 n.3.

[85] Queue Reform Order, 124 FERC ¶ 61,183 at P 44.

[86] MISO asserts that the amount is $300 million.

68. There is another problem to which commenters give short shrift: late-stage terminations. Commenters suggest that a 15 percent attrition rate (i.e., 15 percent of the projects that met the M2 milestone between 2009 and today have dropped out of the Definitive Planning Phase) does not warrant this queue reform proposal. MISO's Supplemental Filing notes situations where multiple customers have withdrawn from group studies (Group 5 and Definitive Planning Phase Cycle 5). In the case of Definitive Planning Phase Cycle 5, attritions required iterative restudy. MISO states that the same situation could occur for Group 5 if there is an additional termination, and that such restudy would "cause cascading restudies in all subsequent West region group studies in Definitive Planning Phase Cycles 1-9."[87] Commenters do not suggest that this problem will lessen or disappear any time soon. More broadly, we believe that the number of projects that have withdrawn from the interconnection queue at the later stages of the interconnection process is indicative of it being too easy for projects that are not ready to proceed or that are not commercially viable from being able to enter the interconnection queue.

69. In addition, we disagree with those protesters who allege that MISO's proposed justifications for its reforms are inherently discriminatory or that MISO fails to understand the market for wind power and the development of new generation. It is well documented that the influx of generation into MISO's region, driven in part by RPS standards, has posed a challenge to MISO's processing of the queue.[88] In this context, we believe that MISO's statements regarding the imbalance between supply and demand and the relationship between this imbalance and RPS standards do not evince a discriminatory intent on the part of MISO and do not indicate that MISO is attempting to pre-determine market outcomes. Instead, they reflect some of the challenges that have confronted MISO in the past and continue to challenge MISO today.

70. While some protesters argue that MISO's proposal was crafted without stakeholder input, MISO has provided evidence that it considered stakeholder input when it developed its proposal.[89] MISO in fact held stakeholder discussions at ten regularly scheduled Interconnection Practices Task Force meetings and at least two Planning Advisory Committee meetings over approximately the last year.[90] We recognize that the queue reform, as proposed here, is controversial among developers. Nonetheless, we

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[87] Supplemental Filing at 4.

[88] Queue Reform Order, 124 FERC ¶ 61,183 at PP 9-13.

[89] *See* Supplemental Filing at 5, 11 (discussing MISO's consideration of a "non-queue" approach and the formula for calculating the M2 milestone payment).

[90] November 1 Filing at 20.

agree that queue reform at this time is appropriate to improve the existing situation and indeed to prevent the existing situation from getting worse.

71. However, as explained elsewhere in this order, we believe that some elements of this proposal have not been adequately supported, are contrary to Commission precedent, or are unfair to interconnection customers. We will require that MISO modify the proposal accordingly.[91]

72. Further, while we agree with MISO that further reform of the queue is necessary at this time, we direct MISO to submit informational filings detailing the effectiveness of the reforms approved in this order and on compliance. Accordingly, we direct MISO to make informational filings in April 2013, April 2014, and April 2015, detailing the progress in the queue and suggesting any tariff revisions it deems necessary to address identified inefficiencies in its GIP. In these filings, MISO should also detail its ability to meet the timing requirements in its GIP. This report will promote transparency and consistency in processing the current backlog of interconnection requests and future requests.[92]

73. Finally, we will not require MISO to adopt additional timelines and requirements for itself in processing the queue at this time. We emphasize, however, that we expect MISO to make every reasonable effort, consistent with good utility practice, to process its queue in a fair and expeditious manner.

2. Implementation

a. Proposal

74. MISO's revisions to the GIP will apply to nearly all of the projects in the queue. According to MISO, only interconnection requests for projects that are in commercial operation and have an executed GIA as of the effective date of the revised GIP are exempt from the proposed GIP.[93] MISO explains that projects with executed GIAs that are not yet in commercial operation and are subject to restudy will become subject to the

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[91] We address the proposed Net Zero Interconnection Service separately, below.

[92] We note that these filings will be for informational purposes only. The Commission will not notice the filings, nor accept comment on them, and the filings do not require Commission action. The first filing should be submitted by April 1, 2013 in Docket No. ER12-309.

[93] Proposed section 5.1.1.1 of the GIP; November 1 Filing at 10.

GIP in effect at the time of restudy, including the revised M2 Milestone payment in the revised GIP.[94]

75. MISO also notes that a project with an executed "provisional" GIA will not be exempt from the revised GIP, because it is subject to further study.[95] Projects that are currently in suspension under executed GIAs will be automatically subject to restudy under the proposed GIP at the end of their suspension period.[96] Finally, outstanding interconnection requests will have 90 days from the proposed effective date to transition to the new GIP.[97]

76. MISO claims that these transition provisions will result in a more efficient and reliable Definitive Planning Phase by ensuring that those projects that are not yet in commercial operation are ready to proceed through the queue.[98] MISO argues that its transition provisions are consistent with transition mechanisms that have been accepted by the Commission previously.[99]

b. <u>Comments</u>

77. Several parties object to MISO's proposal to apply the revised GIP to existing interconnection customers on the basis that MISO's proposal fails to properly distinguish between early- and late-stage interconnection requests. These parties argue that the Commission requires transmission providers to include transition provisions distinguishing between early- and late-stage interconnection requests in order to accommodate the reasonable reliance of late-stage customers.[100] EPSA and Midwest

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[94] Proposed sections 5.1.1.1 and 8.7 of the GIP; November 1 Filing at 10. As discussed below, MISO further clarified the application of its proposal to existing interconnection requests in subsequent pleadings. *See infra* text accompanying notes 123, 126-130.

[95] November 1 Filing at 10. Under the Tariff, an interconnection customer may request a provisional GIA for limited operation of its generating facility prior to completion of the requisite network upgrades. MISO, FERC Electric Tariff, Attachment X (0.0.0), § 11.5.

[96] Proposed section 8.7 of the GIP.

[97] Proposed section 5.1.2 of the GIP.

[98] November 1 Filing at 11.

[99] *Id.* at 11.

[100] EPSA Protest at 15 (citing Conference Order, 122 FERC ¶ 61,252 at P 19;

(continued…)

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Developers argue that the Commission should require MISO to grandfather all existing interconnection agreements and all pending interconnection requests that have entered the Definitive Planning Phase or that have executed a Facilities Study Agreement. The Midwest Developers add that the Commission should direct MISO to exempt any project that has satisfied the comparable M3 milestone under the current procedures or any project that was in the queue prior to August 25, 2008 (i.e., the effective date of MISO's 2008 queue reform).[101] The Midwest Developers state that the Commission has previously recognized that, at least by the time the GIA is executed, the project's exposure for Network Upgrade and related costs should be capped.[102]

78. Flat Hill states that if the Commission determines that the proposed M2 milestone payment is reasonable it should, at a minimum, reject the proposal to impose the new milestone on virtually all interconnection customers because MISO's proposal would violate Commission precedent requiring MISO to distinguish between early- and late-stage interconnection requests and unlawfully permit MISO to impose tariff changes retroactively. Flat Hill argues that if the Commission does not reject MISO's proposed new milestones outright, the Commission should specifically exempt interconnection customers already in the Definitive Planning Phase from satisfying the proposed milestone requirement.[103]

79. Iberdrola argues that MISO has failed to provide sufficient justification for applying the revised GIP to late-stage interconnection requests. While MISO asserts that it proposes to apply the revised GIP to late-stage projects in order to determine whether a project is ready to proceed or not, Iberdrola states that whether a project can proceed depends on factors beyond the control of the interconnection customer. Iberdrola states that many of the claimed issues leading to the current filing are related to uncertainties over factors that are outside an interconnection customer's control and that

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Queue Reform Order, 124 FERC ¶ 61,183 at P 90; *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114, at P 98 (2009) (*SPP*)); Flat Hill Comments at 5-6; Midwest Developers Protest at 15-16; AWEA and WOW Protest at 18, 21-23 (citing *Calif. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,031, at P 78 (2008); *Calif. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,292, at P 61 (2008), *order on reh'g*, 127 FERC ¶ 61,117 (2009) (CAISO Queue Order)).

[101] Midwest Developers Protest at 20.

[102] *Id.* at 17-18.

[103] Flat Hill Protest at 5-7 (citing *Consolidated Edison Co. of N.Y., Inc. v. FERC*, 347 F.3d 964, 967-969 (D.C. Cir. 2003)).

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interconnection customers should not be held responsible for delays due to MISO's actions in processing the queue.[104]

80. EPSA, AWEA and WOW also claim that MISO's proposal to generically revise existing agreements is contrary to section 205 of the FPA and prior Commission precedent. They state that the Commission has previously determined that MISO may not make a blanket determination that applies new procedures to already executed GIAs and that MISO must demonstrate that its proposed changes to each agreement are just and reasonable.[105] EPSA and AWEA and WOW also state that MISO's proposal would upset settled investment expectations and would send a dangerous signal to the market that project economics are never settled.[106] EPSA maintains that the instant proceeding is simply not an appropriate forum for considering the individual facts and circumstances necessary to determine whether MISO's proposed revisions are just and reasonable with respect to each affected customer and agreement.[107] Moreover, EPSA contends that MISO could not demonstrate that its proposed changes are just and reasonable, either on a generic or an individualized basis, because its proposed changes are inconsistent with the purposes of Order No. 2003, such as promoting efficient siting, because generators with executed interconnection agreements have already made their siting decision, selected their point of interconnection, and committed to fund necessary upgrades.[108]

81. Additionally, EPSA notes that MISO is proposing revisions that would give MISO broad, if not unfettered discretion, to determine whether a restudy of an individual project or group of projects is necessary, in which case it could unilaterally abrogate the existing agreements of the affected customers and the final, binding cost allocations therein.[109]

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[104] Iberdrola Protest at 13-15.

[105] EPSA Protest at 3, 9-12 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 117 FERC ¶ 61,128, at PP 25, 27 (2006) (Order Rejecting Proposed Tariff Revisions), *order on reh'g*, 119 FERC ¶ 61,097, at PP 13-14 (2007) (Order Denying Rehearing); *FPL Energy Marcus Hook, L.P. v. PJM Interconnection, L.L.C.*, 118 FERC ¶ 61,169 (2007) (Marcus Hook III), *order on reh'g*, 123 FERC ¶ 61,289, at P 13 (2008) (Marcus Hook IV)); AWEA and WOW Protest at 18.

[106] EPSA Protest at 3; AWEA and WOW Protest at 19.

[107] EPSA Protest at 13.

[108] *Id.*at 11.

[109] *Id.* at 13 (citing proposed sections 5.1.1.2, 8.7).

EPSA argues that the Commission has previously found that this result is fundamentally at odds with Order No. 2003's goals of providing stability and predictability in the interconnection process.[110]

82. In the event that the Commission accepts the proposed transition provisions, EPSA argues that the Commission should clarify that the new rules will not apply to a customer with an existing interconnection agreement if any part of its proposed generation facility has commenced commercial operation. EPSA states that this issue is important to interconnection customers, such as Mankato Energy Center, LLC (Mankato), which was studied at the full capacity of two phases with an aggregate capacity of 720 MW and whose executed interconnection agreement requires Mankato to fund Network Upgrades necessary to accommodate the full capacity. However, to date Mankato has not secured a power purchase agreement for the output of the second phase of the project and therefore has not constructed the second phase. EPSA states that while it believes that Mankato should be exempt from the revised GIP, MISO might claim that Mankato is subject to the revised GIP because the second phase of the project has not entered service. EPSA requests that the Commission clarify that Mankato, and any other similarly situated customer, will be exempt from the revised GIP.[111]

83. NextEra notes that the proposed tariff language implies that MISO intends to require projects with provisional GIAs to pay the Definitive Planning Phase entry milestone, even if the project is already under construction. Under provisional GIAs, states NextEra, interconnection customers can build and interconnect their projects even if interconnection studies have not yet been completed. NextEra states that the generator can thereby be operating before the interconnection customer enters the Definitive Planning Phase. NextEra further explains that interconnection customers can do this in order to start producing power at an earlier time, but the tradeoff is uncertainty about the network upgrade costs, which have yet to be determined. NextEra argues that the prospect of withdrawing from the queue has long since been eliminated, and the interconnection customer's eventual entry into the Definitive Planning Phase process is a given.[112]

84. E.ON argues that projects that are currently in the Definitive Planning Phase that have met all Definitive Planning Phase milestones, or that have moved to an executed GIA should not be subjected to the "cash-at-risk" milestone. E.ON maintains that such

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[110] *Id.* at 13-14 (citing Marcus Hook III, 118 FERC ¶ 61,169 at P 17; Marcus Hook IV, 123 FERC ¶ 61,289 at P 37).

[111] *Id.* at 16-17.

[112] NextEra Protest at 9-10.

projects have already demonstrated that they are ready to move forward and are progressing through the system, and there is no reasonable basis to penalize these projects. E.ON further asserts that projects that have not completed all the remaining milestones in the Definitive Planning Phase should be given 90 days from the date of the order accepting the "cash-at-risk" milestone to satisfy the remaining Definitive Planning Phase milestones or otherwise be subject to the new milestone.[113] Moreover, E.ON states that a project should not be required to comply with the "cash-at-risk" milestone if the project has an effective GIA regardless of whether the facility is wholly or partially in commercial operation, as there may be a variety of reasons that are beyond the interconnection customer's control that have precluded full or partial commercial operation.[114]

85. AMP asks the Commission to reject the proposal to apply the M2 Milestone under section 8.2, as revised,[115] retroactively to all interconnection requests except for those that are in commercial operation and have an executed GIA. AMP states that retroactively applying section 8.2 to interconnection customers essentially requires projects that have already entered the Definitive Planning Phase to pay MISO to keep their queue position. AMP argues that MISO's proposal should only apply to entities that have not entered the Definitive Planning Phase and thus have not shown that they are eligible under either the currently-effective requirements of section 8.2 or those suggested by MISO in this docket. AMP adds that retroactively applying MISO's proposed revisions to section 8.2 could have the effect of abrogating certain existing GIAs that contain contrary provisions and that MISO should not be permitted to make this type of modification to its GIAs without obtaining its counterparties' assent or satisfying the applicable legal burden for unilateral modification of contracts.[116]

86. Geronimo claims that MISO's proposal would be unfair to existing interconnection customers, who have spent considerable time and resources in securing agreements under the existing tariff. Geronimo notes that the Commission refused to upset settled contracts in the name of greater queue efficiency and grandfathered existing

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[113] E.ON Protest at 33.

[114] *Id.*

[115] *See infra* text accompanying notes 156-166.

[116] AMP Protest at 12-13.

interconnection agreements in Order No. 2003. Geronimo states that the Commission should make the same finding in this case.[117]

87. Detroit Edison asks the Commission to reject MISO's proposal to revise section 5.1.1.2 of the GIP requiring all interconnection requests subject to study or restudy, including those for which a GIA has been executed but the facility has not commenced commercial operation, to comply with the new Definitive Planning Phase milestone requirements.[118] Detroit Edison explains that it is concerned about the impact of MISO's proposal on a project that it is developing which has completed the Definitive Planning Phase and has executed a GIA.[119] Detroit Edison asserts that its project has already met the Definitive Planning Phase milestone requirements that were in effect for its project at the time that the GIA was executed and that no new or additional requirements should be imposed on it. Detroit Edison maintains that these requirements should only apply to new projects and to existing projects without an executed GIA. Detroit Edison states that while MISO argues that its proposed revisions are necessary to accelerate the pace at which generation projects are interconnected to the grid, this concern does not outweigh the importance that the Commission has previously placed on the sanctity of contracts. In this regard, Detroit Edison notes that in Order No. 2003 the Commission expressly chose not to require parties to make any retroactive changes to interconnection agreements in effect at that time.[120]

88. Xcel believes that the new queue reform provisions should apply to all queued projects, including those with a GIA, that are subject to a restudy, unless those projects are in commercial operation. Xcel asserts that there are projects in the queue that are needed to serve the Northern States Companies' native load customers that are being delayed by projects ahead of them in the queue, many of which, Xcel alleges, have no interest or chance of actually moving forward to commercial operation.[121]

89. National Renewable Solutions argues that MISO's proposed revisions should be rejected because they effectively undermine or eliminate an ongoing backfill study. National Renewable Solutions states that two projects that are in the process of

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[117] Geronimo Protest at 2 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 187, 911; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at PP 136-140).

[118] Detroit Edison Protest at 2.

[119] *Id.*

[120] *Id.* at 3-4 (Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 4).

[121] Xcel Comments at 4-5.

developing paid Definitive Planning Phase fees to be included in the Big Stone II backfill study. They state that backfilling studies is one of the welcome reforms from MISO's 2008 queue reform proceeding. However, in this proposal, the M2 milestone payment requirement effectively changes the rules for those projects in the study. This, contends National Renewable Solutions, will result in a re-shuffling of the benefactors, which will have very little regard to original queue positions that initiated the study in the first place. National Renewable Services states that the time and effort of the two project companies will have been disregarded and that the new requirements will subject them to increased competition from better financed, late comers.[122]

c. Answers

90. In its answer, MISO clarifies that, to the extent a project with an executed GIA in place is not subject to restudy, there is no requirement to meet the revised M2 milestone. MISO further clarifies that, for projects that are not in commercial operation but are involved in a restudy, those projects that have met all applicable milestones in an executed GIA have shown sufficient commitment to achieving commercial operation in a timely manner and should not be required to meet the M2 milestone despite having not yet reached commercial operation. MISO states that it will revise section 5.1.1. of Attachment X such that the trigger for exemption from the new GIP, if applicable, would include successful payment of all applicable milestones under an executed GIA.[123]

91. In their response, the Midwest Developers argue that MISO's attempt to address their concerns is unsatisfactory given MISO's past practice of broadly interpreting its authority to restudy projects which have existing GIAs. The Midwest Developers observe that MISO has already attempted to subject numerous developers with GIAs to revised study models and new system upgrade costs after restudy.[124] The Midwest Developers argue that these projects would be subject to the additional risk of both the milestone payment and the new procedures if MISO's proposal is accepted and urge the Commission to reject MISO's proposal to apply its proposal to projects with executed GIAs.[125]

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[122] National Renewable Solutions Protest at 3-4.

[123] MISO December 15 Answer at 11.

[124] Midwest Developers December 20 Answer at 7.

[125] *Id.*

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d. Supplemental Filing

92. In the supplemental filing, MISO clarifies its assertion that a project that is subject to restudy will be subject to the GIP in effect at the time that it receives notice of restudy. Specifically, such project will be subject to milestone payments and will need to execute a new GIA. According to MISO, absent such a requirement, a restudy would effectively provide a suspension period at nominal cost which would provide an inappropriate incentive for interconnection customers to seek out rationales to justify restudy as a means of delay.[126] MISO states that the only exception to this rule is that if the interconnection customer had reached the point under its GIA that the M2 milestone payment would have been refunded,[127] then its readiness will have been determined and MISO would not require payment of the study milestone.

93. MISO asserts that if a restudy indicates that an amended GIA is required, the restudied project would be required to update to the new GIA, and the *pro forma* portion of the GIA would be updated to the then-effective language. MISO clarifies that this would usually require the interconnection customer to meet the Initial Payment that MISO has proposed[128] unless the interconnection customer's pre-amendment filing milestones have resulted in the interconnection customer already meeting this requirement.[129] MISO acknowledges that proposing to update agreements departs from MISO's past practice of amending only the appendices of GIAs after a restudy; however,

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[126] Supplemental Filing at 7.

[127] The M2 Milestone will be fully refundable upon satisfaction of the initial payment milestone pursuant to Article 11.5 of a non-provisional GIA, upon commencement of commercial operation under a provisional GIA under Section 11.5 of this GIP, or in the event the total Network Upgrade cost estimates in the Interconnection Facilities Study increased by more than 25 percent over the Network Upgrade cost estimates in the Interconnection System Impact Study in the Definitive Planning Phase and the interconnection customer withdraws its Interconnection Request.

[128] Article 11.5 of the GIA would require an interconnection customer to make a payment in cash or security towards the total cost of network upgrades. As proposed, the Transmission Owner would elect between requiring the customer to provide either cash equal to 10 or 20 percent of the cost of required upgrades (depending on the time between the initial payment and the In-Service Date) or security equal to 100 percent of the cost of the upgrades.

[129] Supplemental Filing at 8.

MISO maintains that it is doing so in order to increase certainty rather than to prolong uncertainty.[130]

94. MISO cautions the Commission against limiting the application of the new GIP to any pre-determined point in the queue. According to MISO, doing so would bifurcate interconnection requests into two separate queues and would not address the core issue here: the disincentive for projects to move forward without knowing what their revenues will be. MISO states that applying these procedures to all projects will require a business-plan review of each project, with each project determining whether it wishes to proceed through the Definitive Planning Phase or return to the System Planning and Analysis phase until the revenue outlook improves. Additionally, MISO contends that limiting the application of the new GIP to projects that are not yet in the Facilities Study would do nothing to eliminate the situation surrounding the North Dakota Definitive Planning Phase Cycle 5 study, which, MISO notes, has seen three rounds of projects withdrawing and subsequent restudies. MISO states that only by applying its proposed revisions to the GIP broadly and raising the question of project readiness will MISO be able to attain its goal of stopping the constant restudy cycle caused by the churning of projects in and out of the queue.[131]

e. Comments on the Supplemental Filing

95. Iberdrola argues that MISO's assertions in the Supplemental Filing provide additional evidence that its proposal is unduly discriminatory in that it fails to consider the project life cycle for independent power producers (IPPs). Iberdrola argues that MISO's statements, including its assertion that the revised GIP must be applied to all projects in the queue in order to get them to review their business case, evince a complete lack of understanding of how projects are developed, financed, and built. Iberdrola maintains that IPPs cannot determine their revenue outlook until they have an estimate of the actual costs associated with a specific project. Iberdrola states that the GIP provides a process whereby the costs of interconnection are determined, allowing the interconnection customer to evaluate the viability of a project in the market, and that the projects will not know their revenue outlook prior to entering the Definitive Planning Phase without this information.[132]

96. E.ON argues that it is unjust and unreasonable to require a customer to update the *pro forma* portion of an executed GIA if the customer is restudied because the sole

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[130] *Id.*

[131] *Id.* at 9.

[132] Iberdrola February 21 Protest at 4-5.

purpose of a restudy is to identify any further network upgrades that are needed to accommodate the project. Thus, according to E.ON, the only item that must be updated in an existing GIA to accommodate a restudy is the milestone table in the appendix to the GIA to list any new facilities, new costs for these facilities, new deposits, and any new changes in timing for completion. Moreover, E.ON states that while an interconnection customer knows that the cost and timing of required network upgrades may change if a restudy occurs, the terms and conditions of service are otherwise established upon execution of the GIA and it is unjust and unreasonable to subject customers to potentially moving targets as would occur if the entire GIA were updated when a restudy occurs.[133]

97. AWEA and WOW state that MISO has not provided any justification for departing from the practice of limiting the reform to those projects that have not yet executed a Facilities Study Agreement. They maintain that, at a minimum, MISO should limit the application of its proposed amendments to those projects that have not yet signed a GIA, as applying these reforms to projects that have signed a GIA would violate the certainty that the GIA is intended to provide to both the Transmission Provider and the interconnection customer. AWEA and WOW state that, to the extent that MISO seeks to modify the actual terms and conditions of the GIA, it has failed to provide any legal justification for its ability to make such unilateral modifications under section 205 of the FPA.[134]

98. Calpine states that, based on the Supplemental Filing, it appears that MISO is planning to not only modify, but effectively terminate, existing GIAs and that this requirement will apply to projects that are currently in suspension under executed GIAs and to projects – like its subsidiary (Mankato) – where only half of its anticipated Generating Facility capacity has been installed by the Commercial Operation Date. Calpine argues that the Commission should make it clear that MISO may not modify or terminate any existing GIA without the Commission's specific authorization. Calpine states that MISO has conceded, and the Commission has reiterated, that MISO cannot unilaterally terminate a GIA of its own accord. Calpine urges the Commission to decline to prejudge the validity of any GIA modification or termination proceedings. Moreover, Calpine states that while it is unclear whether MISO plans to attempt to terminate Mankato's GIA, any attempt to do so would be inequitable and unreasonable.[135] Calpine

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[133] E.ON February 21 Protest at 10-11.

[134] AWEA and WOW February 21 Protest at 11-12.

[135] Calpine Protest at 6-9.

states that the Commission should require MISO to explain in more detail how it would implement its proposal.[136]

f. Answers

99. MISO claims that timely application of the proposed revisions to existing projects is necessary to avoid the immediate need for numerous unexecuted filings that will be triggered for projects in Group 5 under the existing process. MISO explains that applying the revised GIP would permit many existing projects to return to the System Planning and Analysis phase if they are not ready to proceed, rather than forcing them to proceed with withdrawals or unexecuted filings at the Commission.[137]

g. Commission Determination

100. We find that MISO's proposed transition provisions are just and reasonable. While MISO is proposing to apply the revised GIP to projects in the later stages of the interconnection process, as discussed further below, we find that doing so is reasonable in light of the issues that MISO is experiencing in administering its queue. However, we will require MISO to revise its Tariff such that existing interconnection customers have 90 days after the issuance of this order – instead of 90 days after the effective date of MISO's revisions (January 1, 2012) – to transition to the revised GIP. Moreover, we will reject MISO's proposed transition provisions to the extent that MISO interprets these provisions as granting it the authority to require interconnection customers with existing GIAs to modify the body of these agreements to reflect the revisions to the *pro forma* GIA accepted in this proceeding if the customer is subject to restudy. We find that if MISO wants to revise the body of an existing GIA to reflect the revisions to the *pro forma* GIA accepted in this proceeding, it must file each agreement that it proposes to modify with the Commission and demonstrate that its proposed revisions are just and reasonable.

101. In order to avoid potential confusion, we will clarify our understanding of MISO's proposed transition provisions. Under MISO's proposal, interconnection customers with "outstanding requests" are required to transition to the revised GIP within a reasonable amount of time not to exceed 90 days. MISO defines "outstanding requests" to include any interconnection request that, on the effective date of the GIP, has been submitted but not yet accepted by MISO, any interconnection request that has an interconnection agreement that has not yet been submitted to the Commission for approval, any interconnection request that has an interconnection study agreement that has not yet been

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[136] *Id.* at 9.

[137] MISO March 7 Answer at 5-9.

executed, or any interconnection request that is in the process of being studied (including restudies).[138] Additionally, under MISO's proposal, interconnection customers that are subject to restudy will be restudied under the revised GIP, as modified on compliance.

102. While all interconnection requests with outstanding requests will be required to transition to the revised GIP, MISO proposes to exempt certain interconnection customers from the requirement to meet the revised M2 milestone, including the new M2 milestone payment. First, projects that have an executed GIA and that have commenced commercial operation as of the effective date of the revised GIP will not be required to meet the revised M2 milestone. Second, those projects that have a GIA prior to the effective date of the revised GIP and that are not subject to restudy will not be required to meet the revised M2 milestone. Third, as MISO acknowledges in its answer and the Supplemental Filing, the following projects also will not be required to meet the revised M2 milestone: (1) a project that is subject to restudy and has been meeting milestones under an existing GIA; and (2) a project that is subject to restudy but has reached the point under its GIA where the M2 milestone payment would have been refunded.[139]

103. We note that MISO's proposed transition provisions do not currently indicate that those projects that fall within (1) and (2) will not be required to meet the revised M2 milestone, as clarified in MISO's pleadings in this proceeding. Therefore, we will direct MISO to submit a compliance filing revising its transition provisions to clarify that these projects will not be required to meet the M2 milestone.

104. We further note that, under MISO's proposal, projects with outstanding interconnection requests are required to transition to the revised GIP, including, where applicable, the revised M2 milestone, within 90 days of the proposed effective date of the revised GIP (i.e., 90 days after January 1, 2012). In effect, this would require projects to meet these requirements one day after the issuance of this order (March 31, 2012). Under the circumstances, we find that doing so would be unjust and unreasonable. Accordingly, we direct MISO to submit, within 30 days of the issuance of this order, a compliance filing revising section 5.1 of its tariff so that the transition period begins upon the issuance of an order approving the revised GIP, giving interconnection customers 90 days from the latter date to comply.

105. While we agree that MISO's proposal is reasonable under the circumstances, we are concerned by MISO's statement that it plans to require a project with an existing GIA that is subject to restudy to revise the body of its GIA to conform to the revised *pro forma* GIA which in turn would subject the interconnection customer with a previously

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[138] Proposed section 5.1.2.

[139] MISO December 15 Answer at 11; Supplemental Filing at 7-8.

executed GIA to MISO's proposed Initial Payment requirement. In essence, it appears that MISO is interpreting its proposed transition provisions as granting it the authority to require an interconnection customer to modify the body of its interconnection agreement. As an initial matter, we note that MISO's interpretation may be inconsistent with Article 11.3.2 of the *pro forma* GIA, which states that, in the case of restudy, the parties "agree to amend Appendix A to [the agreement] . . . to reflect the results of any restudy required under Article 11.3.2." While the text of Article 11.3.2 does not prohibit the body of the GIA from being modified in the case of restudy, such modification can not be compulsory. Further, we agree with those commenters who assert that, consistent with Commission precedent, MISO should be required to file each agreement that it proposes to modify with the Commission and demonstrate that its proposed revisions are just and reasonable.[140] Accordingly, we reject MISO's proposal to require, on a generic basis, interconnection customers with existing GIAs that are subject to restudy to revise their GIAs, without prejudice to MISO filing with the Commission each agreement that it proposes to modify and demonstrating that its proposed revisions are just and reasonable.

106. We disagree with those commenters that argue that MISO's proposal should be rejected because it will affect late-stage interconnection requests. While we acknowledge that MISO is proposing to apply its revisions to the GIP to a broader array of projects than it has in the past, we find that MISO's proposed transition provisions are reasonable under the circumstances. In the Conference Order, the Commission recognized that reforms that affect interconnection requests in the later stages of the interconnection process create special circumstances that require careful considerations because such reforms can significantly disrupt the activities of customers who may have relied upon the existing process. However, the Commission recognized that it may be necessary in some circumstances to apply reforms to late-stage interconnection requests to resolve current backlogs.[141] Here, MISO has submitted evidence indicating that there is a backlog in its queue and that a substantial number of terminations in the queue are at or beyond the point of entering the Definitive Planning Phase. In light of these facts, we agree with MISO that limiting MISO's proposed revisions to projects that are before or after some pre-determined point in the queue (e.g., exempting projects that have a Facilities Study underway or that have entered the Definitive Planning Phase) would create bifurcation in the queue and would not address the problems identified by MISO. Accordingly, we find that MISO's proposal to apply the revised GIP to outstanding requests while exempting those projects that have demonstrated readiness from meeting the revised M2 milestone, including the M2 milestone payment, to be a reasonable

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[140] *See, e.g.*, Order Rejecting Proposed Tariff Revisions, 117 FERC ¶ 61,128 at PP 25-27; Order Denying Rehearing, 119 FERC ¶ 61,097 at PP 13-14.

[141] Conference Order, 122 FERC ¶ 61,252 at P 19.

approach. Further, we note that, as mentioned above, MISO must file with the Commission each agreement that it proposes to modify and demonstrate that its proposed revisions are just and reasonable..

107. Finally, we disagree with Flat Hill's argument that, in accepting MISO's proposal, we are unlawfully permitting MISO to impose tariff changes retroactively. On the contrary, MISO is proposing to require projects to comply with the revised GIP on a going forward basis following a prescribed transition period. And as required herein, we are modifying the dates for meeting the new milestones, to permit a reasonable transition period. In response to EPSA and NextEra, we will direct MISO to make a compliance filing clarifying the extent to which it is proposing to apply the revised GIP to projects that have reached partial commercial operation or that are operating under a provisional GIA. While MISO states that projects with provisional GIAs will be subject to the revised GIP, it is unclear whether MISO intends to require such customers that have commenced commercial operation under provisional GIA to meet the M2 milestone in order to remain in the DPP.

3. Two Queues

a. Proposal

108. MISO proposes to revise the structure of the interconnection queue. As under the existing Tariff, MISO will perform a Feasibility Study when an interconnection customer enters the queue, which will provide a preliminary evaluation of the impact of the proposed interconnection request on the transmission system.[142] While MISO's proposal retains the System Planning and Analysis phase and Definitive Planning Phase, MISO explains that it is modifying the System Planning and Analysis phase by removing required timelines to proceed to the Definitive Planning Phase.

109. Under MISO's proposal, a System Impact Study is required to be performed in the System Planning and Analysis phase.[143] MISO states that the interconnection customer will determine the scope of the System Impact Study.[144] According to MISO, this

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[142] Proposed revised section 6.

[143] Proposed Revised section 7.

[144] November 1 Filing at 13. As explained in section 7.3 of the GIP, the System Impact Study will be performed pursuant to the assumptions specified by the interconnection customer in the System Planning and Analysis Study Scope Form. Failure to submit the System Planning and Analysis Study Scope Form within 30 days will result in withdrawal of the interconnection request.

requirement allows the interconnection customer to select the parameters that it wants to have studied, receive those results from MISO, and work to analyze and market its projects. MISO states that this analysis may lead the interconnection customer to request further analysis in the System Planning and Analysis phase, decide to enter the Definitive Planning Phase, or withdraw. MISO claims that its proposal has the benefit of allowing interconnection customers with different business plans to get studies tailored towards their business plan and that its proposal represents an improvement over larger group studies with a "one-size-fits-all" approach.[145] MISO explains that a customer may remain in the System Planning and Analysis phase indefinitely, so long as the interconnection customer "refreshes" its System Planning and Analysis System Impact Study once every 18 months.[146] MISO further explains that an interconnection customer that fails to refresh its System Planning and Analysis System Impact Study will be withdrawn from the queue.[147]

110. To reflect MISO's revisions to the System Planning and Analysis phase and the Definitive Planning Phase, MISO is proposing to replace the defined term "Queue Position" with two new defined terms: "Initial Queue Position" and "Definitive Planning Phase Queue Position." MISO states that it added these definitions to clarify that a project that enters the Definitive Planning Phase will now be assigned a Definitive Planning Phase Queue Position while other projects will retain their Initial Queue Position. According to MISO, projects that have moved into the Definitive Planning Phase will be studied based on this Definitive Planning Phase Queue Position.[148]

b. <u>Comments</u>

111. Several commenters argue that MISO's proposed revisions will limit the amount of information available to an interconnection customer prior to entering the Definitive Planning Phase. In this regard, NextEra argues that, while MISO suggests that it is

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[145] Laverty Testimony at 16-18.

[146] Proposed revised section 7.2 of the GIP requires that the interconnection customer must submit a completed System Planning and Analysis Study Scope form no later than 18 months after the completion of an interconnection study. *See* November 1 Filing at 12 (stating that initially this requirement will be triggered by the completion of a Feasibility Study and that, after that, an updated scope form must be completed every 18 months).

[147] Laverty Testimony at 18.

[148] November 1 Filing at 5.

revising the GIP to improve customer service, MISO's proposal will require interconnection customers to make significant commitments without having superior information on which to act.[149] Iberdrola states that MISO's proposal provides limited access to the information necessary to make critical business decisions until after a project meets the M2 milestone and enters the Definitive Planning Phase because the interconnection customer determines the scope of the study in the System Planning and Analysis phase – despite the fact that the interconnection customer is at a significant informational disadvantage in identifying assumptions.[150]

112. Xcel expresses support for MISO's proposed revisions to the System Planning and Analysis phase. Xcel maintains that these revisions should result in a product consistent with the interconnection customer's business model. Xcel states that this is a paradigm shift in queue administration and, by affording the interconnection customer flexibility, will help the customer understand project risks and costs by providing meaningful analysis of its individual project. Xcel maintains that this flexibility represents a significant improvement over the existing process and should allow MISO to meet its queue objective of facilitating a "first-ready, first served" approach.[151]

113. MISO Transmission Owners note that several sections of the GIP include references to "applicable Queue Position" or "Queue Position." They state that, because "Queue Position" is no longer a defined term, it should not be capitalized in the GIP or the GIA. MISO Transmission Owners argue that the Commission should direct MISO to revise references to "Queue Positions" or "applicable Queue Position" in sections 3.6 (Withdrawal), 4.3 (Transferability of Queue Position), and 5.5.1 of the GIP to reflect that Queue Position is no longer a defined term and should not be capitalized. Additionally, MISO Transmission Owners state that for the purpose of consistency with the changes in section 5.5.1, the reference to "GIP" in section 5.1.2 of the GIP should be changed to "revised GIP."

c. <u>Answers</u>

114. In its answer, MISO argues that its proposed revisions, including its revisions to the System Planning and Analysis phase, will reduce uncertainty in the queue. MISO states that its proposed revisions to the System Planning and Analysis phase will encourage interconnection customers that are not ready to proceed into the Definitive

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[149] NextEra Protest at 3.

[150] Iberdrola Protest at 9-10.

[151] Xcel Comments at 7-8.

Planning Phase to remain in the System Planning and Analysis phase. MISO notes that an interconnection customer may determine the level of detail that it would like in the study and that refreshing a customer's study may cost as little as $5,000 if the project requests a minimal restudy of the System Impact Study. MISO states that this is a relatively small price to pay for any potentially viable project to remain in the System Planning and Analysis phase without the risk of facing a deadline to proceed.[152]

115. The Midwest Developers argue that MISO's proposal will eliminate any meaningful opportunity for projects that are not yet in the Definitive Planning Phase to obtain the studies necessary to evaluate their likelihood of success. They maintain that MISO's proposal will create a "negative feedback loop" because the Definitive Planning Phase will only be for projects that are ready to proceed, but those same projects will be unable to evaluate their readiness to proceed prior to entering the Definitive Planning Phase. They state that while the interconnection customer will receive some preliminary cost information during the System Planning and Analysis phase, these cost estimates are nonbinding and cannot be relied upon since the study assumptions used in the Definitive Planning Phase may be different than those used in the System Planning and Analysis phase. They state that the resulting process would undermine the ability of customers to determine whether a project is ready to proceed and imposes greater risk on customers.[153]

d. Commission Determination

116. We will accept MISO's proposed changes to the System Planning and Analysis phase. We disagree with those parties that argue that MISO's proposal will limit the amount of information available to an interconnection customer prior to entering the Definitive Planning Phase and find that an interconnection customer should be able to get necessary information through the interconnection customer's judicious use of the System Planning and Analysis Study Scope Form. The System Planning and Analysis Study Scope Form provides the interconnection customer with several study options. For example, an interconnection customer may customize its study by selecting from a range of assumptions regarding the timeframe for study, the transmission and generation facilities included in the model, and outages, to name just a few.[154] We agree with MISO that this flexibility will allow the interconnection customer to obtain sufficient information to make an informed decision about whether its project should proceed to the Definitive Planning Phase. We also note that the Tariff affords an interconnection

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[152] MISO December 15 Answer at 7-8.

[153] Midwest Developers December 20 Answer at 2-3, n.5.

[154] Proposed revised Appendix 2, Attachment A.

customer that believes it needs assistance in identifying the potential costs and risks of its project the option of consulting with the Transmission Provider even before it enters the System Planning and Analysis phase.[155]

117. Although we will accept MISO's revisions to the System Planning and Analysis phase, we will direct MISO to revise its Tariff to remedy certain ambiguities and inconsistencies. First, we note that while the System Planning and Analysis Scope form provided by MISO refers to a "[r]egular Generator Interconnection System Impact Study," a "[p]lanning horizon study," and an "[o]perating horizon study," these terms are not defined. Accordingly, we will direct MISO to submit revisions clarifying the meaning of these terms. Second, we agree with MISO Transmission Owners that references throughout the GIP should be consistent with defined terms. Therefore, we will direct MISO to make the revisions identified by MISO Transmission Owners above.

4. Cash-at-Risk Milestones

118. MISO proposes several revisions that will increase the financial contributions that interconnection customers will be required to make in order to proceed through the queue and will require the interconnection customer to meet these financial requirements earlier in the interconnection process.

a. M2 Milestone Payment

i. Proposal

119. MISO proposes revisions to section 8.2 of the GIP to clarify that a project is eligible to enter the Definitive Planning Phase after having provided: (1) a new capital contribution (M2 milestone payment); (2) technical data requirements; and (3) Definitive Planning Phase study deposit.[156] MISO explains that only the capital contribution is "new." MISO states that it is proposing to replace previously accepted indicia of readiness that the Commission approved in phase one of MISO's queue reform with a requirement that the interconnection customer make a capital contribution in the form of

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[155] MISO, FERC Electric Tariff, Attachment X (0.0.0), § 6.1.

[156] Together, these requirements are commonly referred to as the M2 milestone. Under the currently-effective tariff, entry into the Definitive Planning Phase requires a project to meet the M2 milestone. Queue Reform Order, 124 FERC ¶ 61,183 at P 65.

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cash or an irrevocable letter of credit because it has determined that a capital contribution provides a better indicator of a project's readiness to proceed.[157]

120. MISO explains that the amount of the required capital contribution will be based upon a formula that considers the interconnecting zone's schedule 7 $/MW year long-term firm point-to-point transmission service rate, the MW size of the facility, and the number and cost of constraints.[158] MISO states that it initially considered a deposit equal

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[157] Currently, interconnection customers are required to demonstrate readiness to proceed to the Definitive Planning Phase by providing two of six possible demonstrations of readiness, only one of which involves a capital contribution. An interconnection customer also has the option of providing additional security reasonably acceptable to MISO equal to the requested gross nameplate capacity times the rate for one month of drive-out point-to-point transmission service in lieu of certain other non-cash options including, e.g., that turbines have been ordered.

[158] Specifically, as proposed, section 8.2 provides that the M2 milestone payment will be calculated based on the following formula:

> Ten percent (10%) of the sum of the following calculation, with a minimum charge of $2,000 per gross MW addition and a maximum charge of $10,000 per gross MW addition:
>
> (Schedule 7 $/MW yearly rate for interconnecting Zone multiplied by the gross MW capacity increase to the Generating Facility) + (Constant $ amount per table below for each voltage level multiplied by the number of constraints shown in Feasibility Study, for that voltage level)

Feasibility Study Constraint Voltage level	Constant $ amount
345 kV	$350,000
230 kV	$200,000
161 kV	$130,000
138 kV	$130,000
115 kV	$130,000
69 kV	$125,000

to approximately 10 percent of the expected transmission costs of a project, which would historically result in about 1 percent of the overall project cost. MISO states that it considered two different algorithms for determining the amount of the required capital contribution: (1) analyzing the transmission costs of projects with interconnection agreements and developing a "best-fit" line formula to compute 10 percent of the expected costs; and (2) taking into account the location of the interconnection and the results of the Feasibility Study. MISO explains that it decided to use the latter because it was more forward-looking and keeps the emphasis on the Feasibility Study. MISO states that its chosen method closely matches 10 percent of expected transmission costs if a 10 percent multiplier is used. MISO notes that its formula also includes floors and caps in order to ensure both that every project has some milestone payment charge and that the charge does not exceed a reasonable range.[159]

121. MISO states that it is proposing an "off-ramp," which provides that the M2 milestone payment will be refunded in certain circumstances: (1) upon satisfaction of the Initial Payment milestone in Article 11.5 of a non-provisional GIA;[160] (2) upon commencement of commercial operation under a provisional GIA; or (3) if the total network upgrade cost estimates contained in the Interconnection Facilities Study performed in the Definitive Planning Phase increase by more than 25 percent over the network upgrade cost estimates in the System Impact Study performed in the Definitive Planning Phase and the interconnection customer withdraws its interconnection request.[161] MISO explains that the M2 milestone payment will be forfeited if the project otherwise withdraws.[162]

122. MISO explains that it determined that the amount of capital available to a project is the best indicator of whether a project will proceed after reviewing key requirements to interconnect a generator. MISO notes that, in contrast to 2008, it is now relatively easy to get a turbine order. MISO further states that non-monetary milestones such as a turbine order come in many forms, and, as a result, MISO is required to expend time and resources to judge whether or not a particular milestone submittal is sufficient evidence of a turbine order. MISO states that while turbine orders, environmental permits, and other requirements are important, what distinguishes projects that will go forward from ones that will not is how well a project is financed and whether investors believe in the

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[159] Laverty Testimony at 22-23.

[160] The Initial Payment milestone is discussed further below. *See infra* text accompanying notes 230-231.

[161] November 1 Filing at 15; Proposed section 8.2; Laverty Testimony at 23.

[162] Laverty Testimony at 20.

project's business plan. MISO notes that there is less ambiguity when it comes to cash and that, irrespective of the project's business structure, the risk falls on the investor.[163]

123. MISO argues that its proposal aims to expedite the queue process and meet the goals of Order No. 2003 by requiring an additional payment as projects progress while also allowing projects to control how long they remain in the System Planning and Analysis phase of the queue indefinitely and obtain tailored study results.[164] MISO contends that its proposal is consistent with the guidance provided in the Conference Order because it balances the needs of different generator interconnection projects and prioritizes the processing of requests on a fair basis to ensure that the flexibility for individual generators does not undermine the certainty and speed needed for the queue as a whole. Moreover, according to MISO, its methodology appropriately addresses the impact on small interconnection customers by basing the required milestone on the size of the project and the number of constraints.[165] MISO notes that it rejects the contention by some stakeholders that the new M2 milestone payment favors regulated utilities. MISO maintains that this assertion is based on the flawed assumption that utilities will be able to easily obtain approval from their regulatory authority to simply recover any lost capital as part of its rate base. MISO states that the risk will be the same for both regulated utilities and independent developers: any forfeited deposits are charged to the company.[166]

ii. <u>Comments</u>

124. Several commenters argue that MISO has failed to demonstrate that the M2 milestone payment will demonstrate project readiness. AWEA and WOW state that MISO has failed to explain why past financial deposit increases have been insufficient to ensure readiness or why its proposed non-refundable capital contribution will be effective or just and reasonable. AMP, Flat Hill, and the Midwest Developers argue that, unlike existing milestones, which are based on actual achievement of project-related progress, the proposed M2 milestone payment merely shows which entities have the most money.[167] The Midwest Developers and AMP argue that it is not necessarily the case

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[163] *Id.* at 19-20.

[164] November 1 Filing at 15 (citing Queue Reform Order, 124 FERC ¶ 61,183 at PP 17, 79; Conference Order, 122 FERC ¶ 61,252 at P 17).

[165] *Id.* at 16.

[166] Laverty Testimony at 20.

[167] AMP Protest at 9-10; Flat Hill Protest at 5; Midwest Developers Protest at 21.

that parties with the ability to put significant dollars at risk early in the study process are more likely to succeed in developing a power plant or to do so more efficiently.[168] AMP states that it would support replacing the options available under the currently-effective GIP requirements with MISO's new proposed capital contribution as an alternative for those customers that are unable or unwilling to enter the Definitive Planning Phase under the existing system.[169]

125. Commenters also claim that MISO's proposal is contrary to Commission precedent. AWEA and WOW state that while the Commission has afforded regions the flexibility to propose solutions to backlogs in the queue, the Commission has directed RTOs and ISOs to first consider whether they have used all of the effective steps provided for by their current tariffs or as explicitly authorized in Order No. 2003.[170] AWEA and WOW further state that while the Commission has indicated that increasing deposit amounts may be one suitable way of addressing queue backlogs, the Commission has recognized that proposals to do so should not result in undue discrimination between types of developers and that there must be a balance between flexibility to demonstrate readiness and having a functioning queue process. AWEA and WOW claim that MISO's proposal is contrary to this guidance because MISO is proposing to replace the *options* available to demonstrate readiness under the current tariff with a single demonstration of financial resources. According to AWEA and WOW, MISO's proposal is geared more towards alleviating its own administrative burdens than providing a service that works well for its diverse customer base.[171]

126. A number of commenters argue that the proposal unduly discriminates against IPPs and is unduly preferential to generators affiliated with vertically-integrated Transmission Owners.[172] The Midwest Developers, Iberdrola, and AWEA and WOW argue that MISO has failed to demonstrate that the proposal will not discriminate between load serving entities (LSE) that have the capability of recovering expenses by

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[168] Midwest Developers Protest at 21; AMP Protest at 9-10.

[169] AMP Protest at 10.

[170] AWEA and WOW Protest at 10 (citing Conference Order, 122 FERC ¶ 61,252 at P 8).

[171] *Id.* at 12-13.

[172] *Id.* at 14; EPSA Protest at 20-21; Midwest Developers Protest at 22-23; Iberdrola Protest at 11-13; Juhl Protest at 3-4.

including these costs in rate base and IPPs who have no such option.[173] AWEA and WOW add that while there is no certainty that an LSE developer would be able to recover a forfeited milestone as a prudently incurred investment in a rate proceeding, rate-making principles in some states suggest that this is a real possibility. AWEA and WOW further add that an LSE developer should have access to more reliable information in the System Planning and Analysis phase, and thus be in a better position than an IPP to evaluate expected costs and the decision on whether to pay the M2 milestone payment.[174] Similarly, Iberdrola argues that MISO has failed to provide any discussion regarding the impact of its proposal on different classes of customers, despite the fact that the risk to IPPs varies significantly from that of LSEs.[175] Iberdrola and EPSA state that, unlike an IPP, utility-affiliated generators can finance projects based on the balance sheets of their regulated parents.[176]

127. A number of commenters argue that the M2 milestone payment creates a chicken-and-egg problem for developers. AWEA and WOW note that MISO acknowledges that before committing funds to satisfy the M2 milestone payment, a customer would need MISO to provide information about the transmission upgrades needed, or, more likely, a reasonable set of bounds around these costs; yet, at the same time, MISO acknowledges that the results of studies in the System Planning and Analysis phase cannot be relied upon specifically because, under MISO's proposal, the scope of studies in the System Planning and Analysis phase will be determined by the interconnection customer.[177] Likewise, EPSA states that, without an interconnection agreement, lenders will typically not provide financing for projects and purchasers will often decline to enter into PPAs with developers. At the same time, without financing or a PPA, asserts EPSA, an interconnection customer will not be in a position to satisfy the M2 milestone payment.[178]

128. Juhl argues that MISO's proposed revision would create an unfair economic burden upon small wind projects, including "community wind" projects whereby a larger

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[173] AWEA and WOW Protest at 13-14; Midwest Developers Protest at 22-23; Iberdrola Protest at 12-13.

[174] AWEA and WOW Protest at 13-14.

[175] Iberdrola Protest at 11.

[176] EPSA Protest at 21; Iberdrola Protest at 12.

[177] AWEA and WOW Protest at 15-16.

[178] EPSA Protest at 21. *See also* Iberdrola Protest at 12.

percentage of wind farm proceeds are shared with local interests. According to Juhl, the imposition of these costs would result in a complete shift in competition and the possibility of eliminating small wind altogether and ensuring that only a small group of larger, well funded energy/electric utility conglomerates would be the only market players able to survive. This, Juhl asserts, would completely undermine the Commission's goal of lowering wholesale prices for customers by increasing the number and variety of new generation that will compete in the wholesale market and, due to general trends of consolidation, will result in increased wholesale prices.[179]

129. ARES also contends that the proposal discriminates against smaller projects because the cost of the milestone is significantly higher per MW of nameplate capacity for a 20 MW project as opposed to a much larger project. Specifically, ARES states that the cost is significantly higher per MW of nameplate capacity for a 20 MW project as opposed to much larger projects (up to ten times as high). ARES suggests that a straight-line deposit framework would be more appropriate.[180] Further, ARES asserts that past milestones already demonstrated financial commitment and asks the Commission to direct MISO to revise its Tariff to eliminate further Definitive Planning Phase entry milestone deposit requirements for projects that are less than 25 MW in nameplate capacity and entered the MISO queue prior to September 1, 2008.[181]

130. Several commenters also argue that, if the M2 milestone payment is accepted, the Commission should require MISO to modify the formula for calculating the required capital contribution.[182] For instance, the Midwest Developers, Iberdrola and AWEA and WOW criticize MISO's use of zonal rates to determine milestone payment costs. The Midwest Developers assert this would result in disparate treatment of similarly sized projects in different zones based solely on location.[183] Iberdrola states that zonal rates have little to do with interconnection costs and argues that the Commission should direct MISO to modify its calculation of the M2 milestone payment so that it relates to the estimated study costs and the risk of restudy upon withdrawal.[184] AWEA and WOW

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[179] Juhl Protest at 3-4.

[180] ARES Protest at 1, figure 1, figure 2.

[181] *Id.* at 1.

[182] Midwest Developers Protest at 23; AWEA and WOW Protest at 15; Iberdrola Protest at 19.

[183] Midwest Developers Protest at 23-24 (noting that a hypothetical presented in the stakeholder process demonstrated that similarly-sized projects located in two different areas within MISO could face a 4:1 difference in the size of their milestone payments).

[184] Iberdrola Protest at 19-20.

suggest using an average of schedule 7 rates or something similar to ensure equal treatment across zones.[185]

131. Commenters also object to the circumstances under which the M2 milestone payment will be refunded. EPSA argues that MISO's proposal to require forfeiture of the M2 milestone payment, except under limited circumstances, should be rejected because MISO has failed to justify the need for such punitive measures. EPSA states penalties are only justified where a participant has violated some rule, regulation, or tariff provision, and withdrawal or termination of an interconnection agreement does not violate any such rule. EPSA maintains that MISO has failed to show that the preconditions for imposing punitive measures have been satisfied because MISO has failed to demonstrate that the measures are narrowly tailored to deter the alleged abuses and will not deter legitimate projects from progressing through the queue.[186] EPSA further contends that the M2 milestone payment is a deposit and that Commission precedent requires transmission providers to refund deposits in excess of actual costs.[187] Iberdrola raises a similar argument and argues that the Commission should order MISO to refund all amounts above the costs associated with any restudies, with interest, following withdrawal.[188]

132. If the Commission accepts the M2 milestone payment, EPSA states that, at a minimum, the Commission should eliminate the forfeiture requirement or require MISO to refund the M2 milestone payment under a wider range of circumstance, as it has done in other circumstances. Additionally, EPSA states that the Commission should adopt a maximum cap on the amount that can be forfeited, such as the lesser of half the amount posted or $2 million. EPSA maintains that the risk of forfeiting up to $2 million should be more than adequate to deter speculative projects while not penalizing projects that are forced to withdraw due to forces beyond their control.[189]

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[185] AWEA and WOW Protest at 15.

[186] EPSA Protest at 22 (citing *Sierra Pac. Power Co. and Nevada Power Co.*, 92 FERC ¶ 61,179, at 61,627 (2000); *Entergy Servs., Inc.*, 88 FERC ¶ 61,098, at 61,233-34 (1999); *Mirant Kendall, LLC and Mirant Americas Energy Mktg., L.P.*, 110 FERC ¶ 61,272, at P 17 (2005)).

[187] EPSA Protest at 23 (citing Queue Reform Rehearing Order, 127 FERC ¶ 61,294 at P 13; *SPP*, 128 FERC ¶ 61,114 at P 67).

[188] Iberdrola Protest at 9, 20.

[189] EPSA Protest at 24 (citing CAISO Queue Order, 124 FERC ¶ 61,292 at P 135).

133. The Midwest Developers argue that the Commission should make the M2 milestone payment fully refundable upon the interconnection customer's withdrawal from the Definitive Planning Phase, as the act of posting an expensive deposit is itself a strong sign of commitment by the interconnection customer.[190] The Midwest Developers, along with AWEA and WOW, maintain that, even if the Commission does not make the deposit fully refundable, it should require MISO to refund the milestone payment where the customer withdraws and the estimate in either the Feasibility Study or the System Planning and Analysis System Impact Study exceeds that in the Definitive Planning Phase System Impact Study.[191]

134. AMP argues that the Commission should direct MISO to use a cost differential of 20 percent instead of 25 percent for the purpose of determining whether a refund should be provided to the interconnection customer upon its withdrawal. AMP argues that its proposals would create an incentive for MISO to adopt more accurate cost estimates.[192]

135. EPSA, Iberdrola, AWEA, and WOW note that MISO does not clearly disclose what happens to forfeited deposits and that the retention of these funds is unjust and unreasonable.[193] Among other things, these parties argue that MISO must disclose how it will treat forfeited funds and justify its proposal to the Commission.[194] AWEA and WOW argue that any forfeited Definitive Planning Phase milestones should be credited back to the benefit of interconnection customers and not used as a way to transfer funds to transmission customers. AWEA and WOW ask the Commission to direct MISO to clarify how these funds are credited and to require MISO to credit forfeited funds in such a way that the parties most affected by the withdrawal benefit from the forfeited funds.[195]

136. Xcel notes that the Interconnection Practices Task Force struggled to develop a fair and equitable solution that would be applicable to all projects regardless of size or generation type. Xcel states that it is optimistic that the M2 milestone payment, along with other changes proposed by MISO, will be enough for the process to operate

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[190] Midwest Developers Protest at 25-26.

[191] *Id.* at 26-27; AWEA and WOW Protest at 17.

[192] AMP Protest at 11.

[193] EPSA Protest at 22-23; Iberdrola Protest at 20; AWEA and WOW Protest at 39.

[194] *See, e.g.*, Iberdrola Protest at 20.

[195] AWEA and WOW Protest at 38, 39.

efficiently and meet the first-ready, first-served objective of Attachment X. However, Xcel states that it further believes that the size of the M2 milestone payment is the minimum necessary to provide the proper indication of readiness and, therefore, requests that these amounts not be reduced. Xcel would support a more rigorous financial milestone in order to ensure the success of the proposed reforms. Xcel also feels that MISO's proposed "off-ramp" is reasonable.[196]

iii. Answers

137. MISO states that it inadvertently omitted a formula for the application of forfeited milestone funds. MISO explains that it plans to use the forfeited funds to offset MISO administration costs by, for example, crediting such funds to schedule 10. MISO states that it has reviewed AWEA and WOW's suggestions and will continue to examine its schedules to find a way to offset study costs with forfeited funds. MISO states that, in the event that it develops a workable method to do so, MISO can move the forfeited funds to offset engineering study costs at that time.[197]

138. Noting that they support the use of forfeited funds to offset engineering study costs, the Midwest Developers argue in response that the vague assurances provided by MISO in its answer do not go far enough because MISO is still seeking to use such funds to offset its administrative costs. The Midwest Developers maintain that it is essential that such funds be used to reduce the cost of affected interconnection customers because funds committed to the interconnection study process should remain in that process and not be swallowed up into MISO's broader budget. Therefore, they state that the Commission should direct MISO to revise its tariff to apply any forfeited milestone funds to offset affected customers' study costs.[198]

iv. Supplemental Filing

139. In the supplemental filing, MISO provides further details about the formula for calculating the new M2 milestone payment. MISO states that it originally intended the formula to approximate the expected costs of network upgrades required for service.[199]

140. MISO explains that it proposed a preliminary methodology for calculating the payment using factors such as the location of the transmission upgrade, the size of the

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[196] Xcel Comments at 5-6.

[197] MISO December 15 Answer at 14.

[198] Midwest Developers December 20 Answer at 8.

[199] Supplemental Filing at 9.

project, the cost of upgrades, turbine type, and interconnection kilovolt level. MISO ran regression analyses on historical data in order to determine the relationship between these variables and upgrade costs. MISO states that after it ran several models, it chose the model that included two factors – the size of the unit and the service type of the request -- as the best indicators of upgrade costs. MISO explains that after applying this formula, the total payment appeared to be too high and, in order to reduce the cash exposure of all customers, MISO updated the formula by using only 10 percent of the updated costs. Additionally, MISO states that it proposed caps and floors that would serve as reasonable bounds to ensure that the amount of the capital contribution is between 0.25-0.65 percent of the total installed costs of the project. MISO notes that historically the total cost of transmission for a project has been 10-15 percent of the cost of generation.[200]

141. MISO notes that it selected 10 percent of the transmission costs because it was half of the 20 percent down payment encouraged in the housing market and appeared to be a reasonable starting point for the analysis. MISO claims that stakeholders did not object to the regression formula and the use of a 10 percent factor; however, a few stakeholders expressed concern that the use of a linear regression model could inflate the required capital contribution for projects that were located in areas with no significant congestion and could interconnect with fewer upgrades. MISO explains that while it initially considered the location of the transmission upgrade as one of the factors that should be included, its regression models were unable to identify any reasonable relationship between the network upgrade costs and the geographical location of the upgrades. In order to address these concerns, MISO states that it decided to use the Schedule 7 point-to-point transmission delivery rate to approximate the relationship between the cost and location of the upgrade.[201]

142. MISO states that the cap and floor values incorporated within its formula were crafted with stakeholder input. MISO explains that it initially proposed caps and floors with the goal of keeping the dollar cap within a .25-.65 range of the total installed cost of a wind project, assuming $2 million per MW installed. According to MISO, a number of stakeholders expressed concerns that MISO's approach was biased because it appeared that it was more punitive to small wind projects because the dollar cap, based on MW size, appeared to be much higher for small projects in comparison to larger projects. MISO explains why several of the alternatives it explored were less satisfactory. In order to address stakeholders' concerns, MISO explains that it proposed a $10,000/MW cap and $2,000/MW floor for all types of requests. MISO states that this methodology

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[200] *Id.* at 10-11.

[201] *Id.* at 11.

ensured that the smaller wind units would not be given a higher dollar cap per MW value and was not based on any specific fuel type.[202]

143. MISO claims that these values produce a just and reasonable result when compared to cash commitments required for other transactions in markets where some kind of monetary commitment is required to hold territorial rights to obtain something. For instance, MISO notes that prospective homeowners are typically required to make a down payment before acquiring a loan and that the amount that interconnection customers will be required to provide is far less than the amount typically required as a down payment towards a house. MISO also claims that the amount that each interconnection customer will be required to pay is reasonable when compared with the amount that other business owners are required to provide before starting a new venture, such as franchises. MISO states that its proposed M2 milestone payment will provide just and reasonable results for projects of various sizes by establishing a minimum floor to show readiness to proceed while linking the size of the cap to the size of an underlying project. MISO asserts that, under its proposal, small generators will pay commensurately smaller deposits than larger generators.[203]

v. Comments on Supplemental Filing

144. Iberdrola maintains that MISO's attempt to analogize the process for interconnection to the real estate market and franchise agreements is inappropriate. Iberdrola asserts that an interconnection customer is not buying a commodity or purchasing rights to a product; the customer is trying to get a cost estimate so that it can determine whether its project can compete in the power market.[204] Iberdrola contends that the GIP must be based solely on the costs incurred by MISO to allow non-discriminatory access to power markets by new entrants and that MISO has failed to address this issue. Instead, according to Iberdrola, MISO proposes to erect a barrier to entry by IPPs and, in the process, eliminate the relatively unencumbered entry that is necessary for competitive markets and that Order No. 2003 sought to promote.[205]

145. AWEA and WOW also argue that MISO's analogy to the real estate market is inappropriate, especially considering the point at which the M2 milestone payment is required, as the certainty and risk in each of these settings is very distinct. AWEA and

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[202] *Id.* at 14-15.

[203] *Id.* at 15-16.

[204] Iberdrola February 21 Protest at 5-6.

[205] *Id.* at 5-6 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 11).

WOW note that a more appropriate analogy would be to the earnest money payment that homeowners make, which tends to be around one percent of the price of a home and is refundable once the consumer receives more information about the home during a home inspection. AWEA and WOW state that what is really needed, in addition to a fully refundable deposit, is Feasibility Study results that provide more reliable information on upgrades and cost estimates that are expected to be within 10 to 15 percent of final costs.[206]

vi. Commission Determination

146. We will conditionally accept MISO's proposal to revise the M2 milestone. As discussed above, MISO continues to experience significant challenges in administering its queue. In light of these challenges, we believe MISO's proposal to require projects to demonstrate project readiness by making a capital contribution is just and reasonable.

147. We find that MISO's proposal is consistent with previous Commission guidance regarding methods to streamline and speed the processing of interconnection requests while remaining faithful to the goals of Order No. 2003. In the Conference Order, the Commission acknowledged that it may be appropriate to increase the requirements for getting a queue position and that such a change would increase the likelihood that only projects that are likely to be commercially viable are in the queue. Here, consistent with this guidance, MISO has determined that existing milestones are no longer sufficient to distinguish those projects that are ready to proceed to commercial operation from those that are not. Specifically, MISO has reported significant numbers of terminations of late-stage projects whose developers had met the existing M2 milestone. And, as stated previously, the consequence of late-stage terminations can be multiple and iterative restudies for lower-queued customers. Thus, if the proposed M2 milestone succeeds in significantly reducing such late-stage terminations, we anticipate that projects with viable business plans will more easily and quickly reach commercial operation. MISO asserts that the amount of capital available to the project is the best indicator of whether the project will proceed to commercial operation.[207]

148. We disagree with those commenters who argue that MISO has failed to show that the M2 milestone payment will demonstrate project readiness. By placing the risk of losing the capital contribution on the customer, each interconnection customer must consider its project and the accompanying risks before making the commitment to enter the Definitive Planning Phase and proceed to commercial operation. In so doing, we believe that the M2 milestone payment will help to ensure that projects that enter the

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[206] AWEA and WOW February 21 Protest at 9-10.

[207] Laverty Testimony at 19.

Definitive Planning Phase are commercially viable and likely to proceed to commercial operation.

149. Additionally, we disagree with those commenters that assert that the proposed M2 milestone payment will merely distinguish projects that have financial resources from those that do not and is contrary to Commission guidance because it does not allow enough customer flexibility in demonstrating project readiness. While we recognize the importance of affording interconnection customers flexibility, the Commission has emphasized that there must be a balance between flexibility to demonstrate readiness and having a functioning queue process.[208] We agree with MISO that its proposal, taken as a whole, strikes an appropriate balance by allowing projects that are not ready to meet the M2 milestone payment with the option to remain in the System Planning and Analysis phase until they are ready to proceed.[209]

150. We also find that the arguments that the M2 milestone payment merely distinguishes projects with financial resources from projects that do not, unduly discriminates against independent developers and creates a chicken-and-egg problem for such entities are without merit. The Commission addressed nearly identical arguments in a case involving revisions to CAISO's generator interconnection procedures.[210] In that case, CAISO had proposed to revise its generator interconnection procedures, which only required an interconnection customer to provide financing for network upgrades after construction commenced, to require an interconnection customer to post security for the cost of network upgrades and interconnection facilities during the study process.[211] Several protesters argued that CAISO's proposal unduly discriminated against independent developers because an interconnection agreement is a precondition to entering into a power purchase agreement, which in turn is a precondition to an independent developer obtaining the financing necessary to post the required the security. The protesters also argued that the requirements were unduly preferential towards utility-affiliated generators because, unlike independent developers, utility-affiliated generators

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[208] *See* Queue Reform Order, 124 FERC ¶ 61,183 at P 79; *see also* Conference Order, 122 FERC ¶ 61,252 at P 14.

[209] November 1 Filing at 16.

[210] CAISO Queue Order 124 FERC ¶ 61,292.

[211] Specifically, CAISO proposed to require an interconnection customer to post financial security in the amount of 20 percent of its total cost responsibility for network upgrades and 20 percent of the total cost responsibility for the relevant Transmission Owner's interconnection facilities within 90 days of the publication of the final Phase I Interconnection Study Report. *Id.* P 33.

could finance projects based on the balance sheets of their regulated parents.[212] The Commission rejected these arguments, stating:

> We find the enhanced financial security provisions to be reasonable. Increasing the financial commitments may make it more difficult for underfunded projects to enter the interconnection process. A portion of underfunded projects may not be utility-affiliated. This does not lead to the conclusion that the heightened requirements are unduly discriminatory. Irrespective of financial security provisions, it is not unreasonable to conclude that under-funded projects are less likely to be completed than fully-funded projects and, thus, are more likely to ultimately drop out of the queue and disrupt queue processing for others. Nonutility projects that are appropriately capitalized should benefit along with all other appropriately capitalized projects from the increased efficiencies of the [revised interconnection] process in having earlier assurances as to their cost responsibilities as well as greater certainty as to their commercial operation date.[[213]]

151. We find that this reasoning is equally applicable here. MISO has proposed to adopt the M2 milestone payment in an attempt to deter speculative projects from entering the queue. All interconnection customers – whether independent or utility-affiliated – will be required to meet the M2 milestone payment in order to enter the Definitive Planning Phase. While underfunded projects may decide to remain in the System Planning and Analysis phase or withdraw from the queue,developers who have sufficiently funded their projects should benefit. Additionally, with respect to the argument that utility-affiliated interconnection customers will have more access to more reliable information in the System Planning and Analysis phase, we find that this concern is unsubstantiated, as all interconnection customers will have access to the same information in the System Planning and Analysis phase and will have the same ability to request tailored study results.

152. Likewise, we disagree with the argument that MISO's proposal discriminates against small projects. We agree with MISO that its proposed methodology for calculating the M2 milestone payment appropriately addresses the impact on small interconnection customers by basing the milestones on the size of the project and the

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[212] LS Power Associates, L.P. and Tenaska, Inc. Protest, Docket No. ER08-1317-000, at 23-24 (filed Aug. 18, 2008).

[213] CAISO Queue Order, 124 FERC ¶ 61,292 at P 151.

number of constraints. We also disagree with ARES's argument that the proposal discriminates against smaller projects because the cost of the M2 milestone payment is higher per MW for smaller entities and that a straight-line deposit framework would be more appropriate. The fact that the M2 milestone payment is higher on a per MW basis for smaller entities does not render the M2 milestone payment unduly discriminatory. The costs that a project faces depend, in part, on its size. For example, larger projects may have lower production or transmission costs because of economies of scale. Likewise, the size of the M2 milestone payment depends on the size of the project at issue. While smaller projects may pay more on a per MW basis, the size of their M2 milestone payment will be smaller than the payments for larger projects. Although ARES may prefer a straight-line framework, we believe MISO's proposal appropriately addresses the effect on smaller projects by taking project size into account in a manner that ensures that the size of M2 milestone payments will be smaller for smaller projects. The fact that ARES has identified some alternative formulation that might be better does not render MISO's proposal unduly discriminatory.[214]

153. We will, however, require MISO to submit a compliance filing to address a deficiency in MISO's proposed formula for calculating the M2 milestone payment. Specifically, we reject MISO's inclusion of a pricing zone specific schedule 7 rate. According to MISO, it included this rate because it believed that it was imperative to address stakeholder concerns by including a "location" factor and that, at the time, the best indicator of costs that had some relationship between the cost and location was the schedule 7 rate. We share the concern expressed by some commenters that the use of the pricing zone specific schedule 7 rate may result in disparate treatment of similarly sized projects without justification. Accordingly, we will require MISO to submit a compliance filing, within 30 days of the date of this order, revising the formula for calculating the M2 milestone payment in a manner that addresses these concerns and proposes a justifiable alternative.

154. We find MISO's "off-ramp" and its proposal to fully refund the M2 milestone payment under a narrow set of circumstances is just and reasonable. As noted above, MISO proposes to fully refund the M2 milestone payment upon satisfaction of the Initial Payment milestone in a non-provisional GIA, upon commencement of commercial operation under a provisional GIA, and if the network upgrade cost estimates contained in the Facilities Study performed in the Definitive Planning Phase are 25 percent higher than the estimates contained in the System Impact Study performed in the Definitive Planning Phase. We find that MISO's proposal is reasonable in light of its goal in adopting the M2 milestone payment: to deter speculative projects from entering the Definitive Planning Phase. By limiting the circumstances under which the M2 milestone

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[214] *See, e.g., Calif. Indep. Sys. Operator. Corp.*, 138 FERC ¶ 61,060, at P 25 (2012) (citations omitted).

payment will be fully refunded, it places the risk on the interconnection customer. We find that requiring MISO to make the M2 milestone payment fully refundable would undermine MISO's effort to increase the certainty that projects that enter the Definitive Planning Phase will complete the interconnection process and commence commercial operation.

155. While we find MISO's proposal to fully refund the M2 milestone payment in a narrow set of circumstances is just and reasonable, we have two concerns relating to the forfeiture of the M2 milestone payment in those instances where the M2 milestone payment is not fully refundable. First, we agree with protesters that forfeited funds should be used to offset the costs to interconnection customers that are affected by another interconnection customer's withdrawal. Although MISO has stated that it will continue to examine its Tariff to find a way to use forfeited funds to offset costs and will apply forfeited funds to schedule 10 in the meantime, we will require MISO to revise its Tariff to do so immediately in order to ensure that forfeited funds are used in a manner consistent with our cost causation policy – that costs are borne by those who cause them.[215] Accordingly, we direct MISO to revise its Tariff, within 30 days of the date of this order, such that forfeited funds are used to offset costs to those interconnection customers that are affected by another interconnection customer's withdrawal.

156. Second, in those situations where the M2 milestone payment is not fully refundable, we agree with protesters that it is not just and reasonable for MISO to retain M2 milestone payments beyond that which are necessary to offset the costs resulting from an interconnection customer's withdrawal. We have previously rejected proposals by MISO and other transmission providers to retain deposits in excess of costs and found that refunding these amounts is consistent with cost causation.[216] Although we acknowledge that the M2 milestone payment is not a deposit, cost causation principles continue to apply. Therefore, we direct MISO to revise its Tariff such that any portion of the M2 milestone payment above the costs resulting from an interconnection customer's withdrawal will be refunded to the withdrawing customer.

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[215] Queue Reform Rehearing Order, 127 FERC ¶ 61,294 at P 13.

[216] *Id.*

b. Elimination of Interest on Refunded Study Deposits

i. Proposal

157. MISO proposes to revise section 3.6 of the GIP to delete the reference to refunding interest earned on the interconnection customer's study deposit.[217] MISO maintains that this is no longer needed due to the shift away from the "first-in, first-out" paradigm, under which the transmission provider's speed in processing the queue ahead of a given request was the main driver for the amount of time an interconnection customer's deposit was retained by the transmission provider. MISO claims that this is no longer the case due to the revisions that MISO is proposing in this filing, as the interconnection customer now has more control over how long it remains in the queue because it can elect to move into the Definitive Planning Phase faster.[218]

ii. Comments

158. Several commenters argue that MISO's proposal is inconsistent with Commission precedent, including Order No. 2003.[219] They argue that the Commission has required transmission providers to pay interest in order to compensate interconnection customers for the lost time value of money.[220] EPSA notes that the Commission has rejected analogous proposals by MISO and others to retain unused study deposits.[221] Iberdrola

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[217] MISO's Tariff requires interconnection customers to make deposits towards the cost of interconnection studies at certain times in the study process. For example, an interconnection customer must pay a study deposit when submitting their interconnection requests. MISO, FERC Electric Tariff, Attachment X (0.0.0), § 3.3.1. Additionally, when entering the Definitive Planning Phase, an interconnection customer is required to make a deposit towards the cost of the interconnection studies in that phase. *Id.* § 8.2. Currently, the Tariff provides that MISO will refund any portion of the deposit, including interest, that exceeds the costs that MISO has incurred or will incur as a result of the withdrawal. *Id.* § 3.6.

[218] November 1 Filing at 8; Laverty Testimony at 35.

[219] EPSA Protest at 28-29; Iberdrola Protest at 16, 24; AWEA and WOW Protest at 23; Midwest Developers Protest at 43.

[220] EPSA Protest at 29 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 723; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 618); Iberdrola Protest at 16, 24; AWEA and WOW Protest at 23-24; Midwest Developers Protest at 43.

[221] EPSA Protest at 30 (citing Queue Reform Rehearing Order, 127 FERC ¶ 61,294 at P 13).

adds that MISO has a fiduciary responsibility to use funds that it collects for the purpose for which they are collected and that allowing MISO to retain interest creates an incentive for MISO to slow the queue to collect additional interest.[222]

159. Commenters also reject the notion that interconnection customers are in control of the study process given that the Tariff does not provide a timeframe in which MISO must provide complete and accurate study results and that the timing of studies and restudies are largely beyond the customer's control.[223] AMP argues that, regardless of which entity is in control of the time that a project remains in the queue, an interconnection customer is entitled to any interest that accrues on the deposit.[224] E.ON states that there is no reason why interest should not be provided when the M2 milestone payment is refunded.

iii. Supplemental Filing

160. MISO notes that it is proposing to eliminate the repayment of interest on study deposits for only those projects that withdraw. MISO states that it is important to note that projects that proceed through the GIP and execute a GIA do not receive any interest on their study deposit under the currently-effective Tariff. MISO maintains that paying interest to those projects that withdraw provides the wrong incentive by rewarding those projects who withdraw and penalizing those that proceed through the GIP.[225]

161. MISO argues that its proposal was based on the philosophy that interest earned is usually tied to the investment intent. MISO states that it believes that the real intent of interconnection customers, during the study process, is not to earn interest on their study deposit, but rather to have their projects evaluated for their business justification. MISO states that the real investment decision is made at the time of the GIA where the interconnection customer is making an investment to earn a return over the life of the project. According to MISO, if a project withdraws and the interconnection customer is unwilling to make the investment to earn a return, then the customer should not expect any interest on its study deposit.[226]

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[222] Iberdrola Protest at 15 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 123; *El Paso*, 137 FERC ¶ 61,101 at P 18).

[223] E.ON Protest at 29-30; Iberdrola Protest at 15-16.

[224] AMP Protest at 8.

[225] Supplemental Filing at 25.

[226] *Id.* at 25-26.

162. Additionally, MISO states that interconnection customers have chosen to enter the queue themselves and, therefore, from MISO's perspective, the study costs should be treated as sunk costs and the customers should not be refunded either the deposit or the interest back after withdrawal of the project. However, MISO states that taking this step would be a drastic change for a few customers. Accordingly, MISO proposes to permit the interconnection customer to be refunded the deposit amount after withdrawal of the project.[227]

iv. Comments on Supplemental Filing

163. E.ON argues that MISO's assertions regarding the purported investment intent of interconnection customers neither justifies MISO's proposal nor represents an apt analogy. First, E.ON states that it does not make sense that it is just and reasonable for the customer to receive a refund of study deposits if its project is withdrawn but is not just and reasonable for the customer also to be refunded interest accrued on those deposits. E.ON states that both should be returned to the interconnection customer. Second, E.ON contends that it is inappropriate to compare the decision to invest in the market and the submission of study deposits, as the interconnection customer has no choice but to submit study deposits if it wants to obtain interconnection service or its request will be withdrawn. Thus, E.ON maintains that it is unjust and unreasonable to penalize the customer if it later decides to withdraw its project because information shows its project will not be economically feasible. Third, E.ON states that the rate of interest is small compared to what the interconnection customer could earn in the marketplace and, presumably, smaller than what MISO earns in the marketplace on the study deposits it holds.[228]

164. AWEA and WOW argue that MISO incorrectly assumes that providing interest creates incentives for parties to drop out of the queue. They note that the interest paid on study deposits is not significant enough to provide an incentive to withdraw from the queue, as the interest is only paid on any remaining amount of the study deposit and the rate of interest is lower than the developer's cost of capital. AWEA and WOW claim that MISO's statement that the elimination of interest on study deposits will discourage speculative projects from entering the queue shows that MISO does not appreciate the role of the interconnection queue. AWEA and WOW assert that all developers entering the queue are speculative in that they need to gather information about what it will cost to interconnect their project to the grid. With respect to investment intent, AWEA and

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[227] *Id.* at 26.

[228] E.ON February 21 Protest at 8-10.

WOW observe that the fact that a developer eventually withdraws does not mean that the developer did not intend on developing the project initially.[229]

v. Commission Determination

165. We will reject MISO's proposal in section 3.6 to eliminate interest on study deposits and direct MISO, within 30 days of the date of this order, to restore the Tariff to the language in effect at the time of this filing.

166. As an initial matter, we note that several parties conflated the actual study deposit with the M2 milestone payment. To be clear, the study deposits required at different points in the GIP are separate and distinct from the M2 milestone payment, which is an indicator of readiness and not a study deposit. MISO's proposal does not alter the approach for determining the size of the study deposit that the Commission accepted in the 2008 queue reform proceeding. Here, we are directing MISO to restore the language of section 3.6 of the GIP, which concerns interest on study deposits upon withdrawal.

167. We find that MISO's proposal to eliminate interest paid on study deposits is inconsistent, as pointed out by numerous protestors, with the Commission's previous precedent. As these protesters point out, the Commission requires payment of interest on collected study deposits to compensate interconnection customers for the time-value of money. We agree with protesters that MISO's assertions that interconnection customers are now in control of the study process and about the purported investment intent of interconnection customers do not provide a reason for departing from Commission policy. Additionally, we agree with protesters' argument that paying interest on study deposits is not significant enough to provide an incentive to withdraw from the queue.

168. However, in light of the reasoning behind requiring the payment of interest on study deposits, we find that it would also be appropriate to require MISO to pay interest on the M2 milestone payment when that payment is refundable. While the M2 milestone payment is an indicator of readiness to proceed and is not a deposit, we believe that it is just and reasonable to require MISO to compensate an interconnection customer for the time-value of money when the M2 milestone payment is refundable to the customer. Therefore, we will also direct MISO to revise its Tariff, within 30 days, to provide for the refund of interest on the M2 milestone payment to an interconnection customer where that payment is refunded to the customer.

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[229] AWEA and WOW February 21 Protest at 7-9.

c. Initial Payment

i. Proposal

169. MISO proposes to revise Article 11, "Performance Obligation," of the GIA to include a new Article 11.5, "Initial Payment," that requires an interconnection customer to make an initial payment in cash or security for the cost of certain network upgrades. Specifically, Article 11.5 states that the Transmission Owner shall elect and require the interconnection customer to provide: (1) an initial payment of twenty percent of the total cost of the project upgrades if the In-Service Date is five or fewer years from the initial payment date; (2) an initial payment of ten percent of the total cost of the project upgrades if the In-Service Date is more than five years from the initial payment date; or (3) the total cost of the project upgrades in the form of security. Article 11.5 also states that the Initial Payment shall be provided within the later of: (a) thirty days of the execution of the GIA by all parties; or (b) thirty days after the Commission accepts the unexecuted GIA if the interconnection customer is disputing the initial payment; or (c) thirty days after the GIA is filed unexecuted with the Commission if the initial payment is not being contested.[230]

170. MISO explains that its proposed Article 11.5 tracks the methodology of the M2 milestone payment by requiring an interconnection customer to make a capital contribution to demonstrate that the interconnection project is viable. MISO maintains that its proposal prevents the interconnection customer from establishing a long lead time for a project and then waiting for the lead time to expire before deciding to withdraw from the interconnection queue without having to expend any capital. MISO states that it expects that projects that are ready to proceed will be able to meet this milestone at this stage and this revision will reduce the concerns with uncertainty about whether a project will proceed.[231]

ii. Comments

171. Numerous parties argue that MISO's proposal discriminates against small developers, and is anticompetitive and inconsistent with Order No. 2003. EPSA states that the Initial Payment requirement is excessive and unduly discriminatory because it gives the Transmission Owner the right to require the interconnection customer to either provide a payment of 10 percent or 20 percent of the total cost of network upgrades or to post security equal to 100 percent of the network upgrade costs. According to EPSA, the Commission rejected requests to require interconnection customers to provide security

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[230] November 1 Filing at 19-20.

[231] *Id.* at 19-20.

equal to the total amount of network upgrades in Order No. 2003 because doing so would have a chilling effect and seriously discourage new generation.[232] Further, EPSA argues that MISO's proposal discriminates against independent developers who would have to first obtain financing for the project in order to post the required amount of security. Specifically, EPSA argues that for independent developers, an interconnection agreement is a precondition to entering into a power purchase agreement, which in turn is a precondition to obtaining the financing necessary to post this security. According to EPSA, thirty days is not a sufficient period of time for an independent developer to raise this amount of capital.[233]

172. AWEA and WOW, and NextEra argue that the addition of Article 11.5 will result in a payment schedule for project upgrades that is not aligned with the need to fund the actual construction of the upgrades.[234] AWEA and WOW allege that MISO is changing the purpose of providing financial security for procurement and construction to serving as another test of project readiness. They maintain that this conflicts with the Commission's holding in Order No. 2003 that the purpose of the security provided is to "fund procurement and construction" and "since it is uncertain when procurement and construction will begin, it is reasonable to make such activity the trigger for tendering Network Upgrades."[235] Additionally, AWEA and WOW argue that MISO must be required to explain why the deposit amounts were selected and how it reached the conclusion that such deposit amounts will not be unduly discriminatory.[236] NextEra argues that there is no legitimate purpose for this requirement, as the payment schedule for network upgrades is already timed towards requiring an interconnection customer to pay the Transmission Owner's costs for building interconnection facilities and network upgrades.[237]

173. AWEA and WOW note that, in Order No. 2003-A, the Commission rejected requests that an interconnection customer be required to maintain full security during the

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[232] EPSA Protest at 25 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 596; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 431).

[233] *Id.* at 25-26.

[234] AWEA and WOW Protest at 25; NextEra Protest at 5.

[235] AWEA and WOW Protest at 25 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 593).

[236] *Id.* at 26.

[237] NextEra Protest at 5.

length of the interconnection process because such a requirement would seriously discourage new generation. AWEA and WOW state that MISO is now actively trying to achieve just such a chilling effect. AWEA and WOW state that MISO has a responsibility to balance the need for adequate financial security to demonstrate project viability with its burden to avoid excessive financial commitments that may discourage development.[238] AWEA and WOW argue that MISO has failed to demonstrate that the amounts required are reasonable and will not overly discourage development, and has failed to provide an adequate explanation for excluding other indicia of project readiness.[239]

174. The Midwest Developers state that the financial impact of proposed Article 11.5 is unjust and unreasonable because it vests Transmission Owners with the authority to exercise control over the payments required by unaffiliated generators and that this represents the kind of impermissible, anti-competitive authority the Commission rejected in *E.ON Climate & Renewables North America, LLC v. Midwest Independent Transmission System Operator, Inc.*[240] Midwest Developers argue that proposed Article 11.5 is no different from Option 1 because each non-independent Transmission Owner will have the sole discretion to determine what financial burden to impose upon interconnection customers.[241]

175. Furthermore, Midwest Developers argue that, for projects with sizable upgrade costs, requiring cash payments of ten or twenty percent of those costs to be made years in advance of the actual construction of the upgrades could effectively sabotage the projects' development if their developers have not yet secured financing for those upgrades. Midwest Developers aver that a more prudent and helpful approach to funding project upgrades would be to require that Transmission Owners develop cash-flow schedules that explain when funds will be required to support design, engineering,

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[238] AWEA and WOW Protest at 26 (citing *Calif. Indep. Sys. Operator, Corp.*, 132 FERC ¶ 61,005, at P 33 (2010)).

[239] *Id.*

[240] Midwest Developers Protest at 33 (citing *E.ON Climate & Renewables North America, LLC v. Midwest Independent Transmission System Operator, Inc.*, 137 FERC ¶ 61,076 (2011) (finding that a provision of MISO's tariff allowing a Transmission Owner to return the costs of constructing network upgrades to an interconnection customer, at the Transmission Owner's election, and to recover these costs over time (Option 1) was unjust, unreasonable, and contrary to Order No. 2003)).

[241] Midwest Developers Protest at 35.

procurement, and construction of project upgrades and that such a schedule could then be the basis for establishing payment milestones.[242]

176. Like other parties, Iberdrola argues that MISO's proposed Article 11.5 only erects another barrier to entry for independent developers and that the payments for project upgrades should be timed to coincide with the construction of those upgrades. Additionally, Iberdrola notes that the filed proposal retains the non-monetary milestone contained in section 11.3 of the GIP.[243] Iberdrola states that that milestone is no longer needed given the changes proposed by MISO and that the Commission should direct MISO to ensure that these types of milestones are consistent throughout the tariff.[244]

177. Finally, in their comments, the MISO Transmission Owners state that the reference to the "initial payment" in Article 11.5 is unclear because three items are listed in the section, two of which are clearly identified as initial payments and a third option which is identified as the total cost provided as security. To clarify that the reference to "an initial payment" is intended to include all three options, MISO Transmission Owners propose that the second sentence of Article 11.5 be revised to read: "The initial payment <u>or security required pursuant to the preceding sentence</u> shall be provided to Transmission Owner by Interconnection Customer…." MISO Transmission Owners state that this change should also be reflected in Appendix B of the GIA.[245]

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[242] *Id.* at 33-34.

[243] Section 11.3 of the GIP requires an interconnection customer to provide, within 180 days after the customer receives the final GIA, reasonable evidence that one or more of the following milestones have been achieved: (i) the execution of a contract for the supply or transportation of fuel to the generating facility; (ii) the execution of a contract for the supply of cooling water to the generating facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the generating facility; (iv) execution of a contract for the sale of electric energy or capacity from the generating facility or a statement by an authorized officer or agent of the interconnection customer attesting that the interconnection customer owns the generating facility and that it is required to serve load; or (v) documentation of application for state and local air, water, land or federal nuclear permits and that the application is proceeding per regulations. MISO, FERC Electric Tariff, Attachment X (0.0.0), § 11.3.

[244] Iberdrola Protest at 21.

[245] MISO Transmission Owners Comments at 12.

iii. Commission Determination

178. We conditionally accept MISO's proposed Article 11.5 of the GIA regarding the size and timing of the Initial Payment after the execution of a GIA.[246] We agree with MISO that the customer's ability to build long lead times into its milestones while taking no action towards achieving commercial operation coupled with the lack of a financial commitment to reach commercial operation has significantly contributed to the problem of late-stage terminations and the potential for cascading and iterative restudies.

179. We disagree with those parties that argue that MISO's proposed Initial Payment is anticompetitive or unduly discriminates against independent developers for the same reasons that we reject similar arguments against the M2 milestone payment above[247] and rejected similar arguments in the CAISO Queue Order.[248] All interconnection customers – whether independent or utility affiliated – will be required to make the initial payment. While underfunded projects may decide to withdraw from the queue, independent developers that have properly funded their projects should benefit from the increased efficiency of the interconnection process. We do not dispute that developers face challenges in order to proceed through the interconnection process and to achieve commercial operation. However, we believe that viable projects would have been laying the groundwork and marketing their projects well ahead of executing a GIA. That is, for projects that are truly viable, the negotiations necessary to finalize business arrangements should be nearly finalized well prior to the actual execution of the GIA such that once the GIA is executed, the other arrangements necessary to obtain funding should be able to be finalized and executed soon after the GIA is executed.

180. With respect to the argument that 30 days is not a sufficient amount of time for an independent developer to raise capital, we note that the interconnection customer will have approximately 105 days from when it learns the size and scope of necessary upgrades to when it will be required to make the Initial Payment. Section 11.2 (Negotiations) of the GIP gives the customer up to 60 days after it receives its draft Facilities Study and/or completed draft GIA to negotiate the final GIA. It also gives the customer an additional 15 days to execute the final negotiated GIA, at which point the time period for submitting the Initial Payment would begin to run. Thus, a customer will have 75 days after initially learning the size and scope of its necessary upgrades plus the

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[246] We note that, as discussed above, we decline to grant MISO authority to modify existing GIAs on a generic basis.

[247] *See supra* section IV.A above.

[248] 124 FERC ¶ 61,292 at P 151.

30-day period in Article 11.5 to raise the necessary capital (105 days total). We find this to be just and reasonable and not unduly discriminatory.

181. We disagree with those parties that argue that the Initial Payment is contrary to Order No. 2003 because it is not tied to the schedule to plan, procure, or construct upgrades. While the Commission declined to require the provision of security at some specified period after the execution of an interconnection agreement in Order No. 2003,[249] the Commission found that independent entities, such as MISO, should have flexibility to customize their interconnection procedures to fit regional needs.[250] Order No. 2003, among other things, was intended to expedite the development of new generation. Based on the evidence provided, we find that the proposed addition of Article 11.5 is consistent with that intention. MISO has provided compelling evidence that, in the current climate, the ability of customers to wait for long lead times to almost expire before terminating their GIA has caused a significant number of restudies to be necessary and that these restudies adversely impact other customers that are trying to reach commercial operation. MISO has demonstrated that the scope of this problem is causing queue churn and is adversely impacting MISO's interconnection process. Therefore, we find that MISO's proposed Article 11.5 has met the independent entity standard.

182. However, we find that MISO has failed to demonstrate that it is just, reasonable, and consistent with Order No. 2003 to permit the Transmission Owner to elect the type of security that an interconnection customer must provide under Article 11.5. MISO has failed to show why the Transmission Owner should be afforded this discretion under proposed Article 11.5, and we are concerned that this language may create opportunities for undue discrimination. Thus, we will require MISO to revise the language of Article 11.5 so that the interconnection customer has the option of meeting the Initial Payment requirement by providing either: (1) a payment equal to 20 percent of the total cost of Network Upgrades, Transmission Owner Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and/or Generation Upgrades if the In-Service Date is less than or equal to five years from the date of the Initial Payment or 10 percent of the aforementioned cost if the In-Service Date exceeds the date of the Initial Payment by more than five years; or (2) security equal to 100 percent of the cost of the aforementioned upgrades. Accordingly, we direct MISO to revise, within 30 days of the date of this order, Article 11.5 as discussed here. Again, we reiterate that this provision shall only apply to new GIAs or those in effect, which MISO seeks to amend through a filing with the Commission.

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[249] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 593.

[250] *Id.* PP 26, 827.

183. Finally, we decline to order MISO to remove the non-monetary milestone in section 11.3 of the GIP as requested by Iberdrola. There does not appear to be an inconsistency between this provision and Article 11.5. The mere fact that MISO is proposing an additional financial milestone in the form of the Initial Payment does not render section 11.3 unnecessary. On the contrary, it appears that MISO intends to require interconnection customers to make the Initial Payment in addition to meeting these non-financial milestones. We find that doing so is just and reasonable.

5. Studies

a. Section 8.7 "Interconnection Study Restudy"

i. Proposal

184. MISO proposes to revise section 8.7 of the GIP to clarify that a restudy will be needed if a project recommences following a suspension.[251] Additionally, MISO proposes to revise section 8.7 to clarify that a restudy will be performed subject to the GIP in effect at the time notice of such restudy is provided by MISO.[252]

ii. Comments

185. E.ON argues that section 8.7 should be revised to make clear that, unless an interconnection customer that suspends work is a higher-queued generator that is specifically identified in studies provided to lower-queued generators or specifically listed in the executed GIA of a lower-queued generator, then such higher-queued generator shall not be subject to restudy. E.ON maintains that this revision would be consistent with sections 11.3.1 and 11.3.2 of the *pro forma* GIA which provide for restudy when certain actions by higher-queued generators occur and with Order No. 2003, which requires the Transmission Provider to list any contingencies in the GIA. At most, according to E.ON, the restudy provision should apply to the interconnection customer once it comes out of suspension.[253]

186. E.ON also points out that MISO is proposing to revise section 8.7 to provide that if a restudy is required, the "Transmission Provider *may* provide notice of restudy" and that "[t]he Transmission Provider's notice *may* include an explanation of why an Interconnection Study restudy is required and a good faith estimate of the cost to perform

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[251] November 1 Filing at 17 n.52.

[252] *Id.* at 17-18.

[253] E.ON Protest at 31.

the Interconnection Study restudy."[254] E.ON argues that the use of "may," instead of "shall," is unjust and unreasonable. E.ON states that the interconnection customer must be provided with notice whenever MISO deems that a restudy is required.[255] Moreover, E.ON notes that MISO is proposing to delete the requirement that the notice include a summary of a preliminary analysis supporting the need for a restudy. E.ON argues that this requirement should be reinstated, as MISO has not provided any testimony supporting why it is no longer just and reasonable for the customer to receive this analysis.[256]

187. The Midwest Developers state that MISO's proposal to expand its authority to restudy a project following suspension is troubling because such restudies previously were intended only to ensure proper scheduling of the interconnection customer's construction efforts coming out of project suspension, rather than to subject the interconnection customer to new procedures. Moreover, they note that the tariff currently provides that an interconnection customer that exercises its suspension rights shall only be responsible for costs specified in Article 5.16.3 of the GIA[257] and that nothing in that Article provides for the assignment of new costs to customers that have already entered into a GIA under the revised GIP.[258]

iii. <u>Supplemental Filing</u>

188. MISO argues that its proposal to revise section 8.7 to clarify that restudy may occur if a project desires to recommence after suspension using the GIP is consistent with Commission precedent, which supports the idea that a restudy may be needed after a

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[254] *Id.* (emphasis added).

[255] *Id.* at 31.

[256] *Id.* at 32.

[257] Article 5.16 states that if an interconnection customer suspends, the customer shall be responsible for all reasonable and necessary costs which Transmission Provider and Transmission Owner have incurred pursuant to the GIA prior to suspension and incur in suspending such work, including the costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the transmission or distribution system during suspension as well as costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Transmission Provider and Transmission Owner cannot reasonably avoid.

[258] Midwest Developers Protest at 17 n.37.

project ends its suspension to account for any changes in the transmission system.[259] MISO maintains that its proposed revisions are consistent with Article 11.3.1 of the GIA addressing contingencies because it clarifies that if a project's own suspension delays its Commercial Operation date, it may trigger the need to restudy that project in the same way that the change to the Commercial Operation Date of a higher queued project may do so. MISO notes that Article 11.3.1 of the GIA allows restudy for eight reasons, with the third item stating that "the Commercial Operation Date for a higher queued interconnection request is delayed such that facilities required to accommodate lower queued projects may be altered." MISO argues that it will revise Article 11.3.1 so that it is clear that these provisions are not in conflict.

iv. Commission Determination

189. We conditionally accept MISO's proposal to revise section 8.7 of the GIP such that a project will be subject to restudy, under the GIP in effect at the time of the restudy, when it comes out of suspension if the Transmission Provider determines that such a restudy is necessary. We disagree with E.ON that MISO should be required to further revise section 8.7 to limit the ability to restudy unless an interconnection customer is a higher-queued generator that is specifically identified in studies provided to lower-queued generators or listed as a contingency in an executed GIA. We also disagree with Midwest Developers that MISO's proposed changes lead to more uncertainty for interconnection customers by potentially requiring new costs to be incurred.

190. MISO has an obligation to ensure that the transmission system is operated in a safe and reliable manner. If MISO determines that a project coming out of suspension needs to be restudied and the result of that restudy causes the interconnection customer to incur more cost in order to safely integrate onto the transmission system, then the interconnection customer is going to have to decide whether to fund the additional costs or to withdraw its interconnection request. Because the decision to suspend is made by the interconnection customer, the interconnection customer assumes a certain amount of risk, and uncertainty, regarding its decision. It is disingenuous to claim otherwise.

191. We agree with MISO, as it explained in its Supplemental Filing, that the proposed revisions are consistent with Article 11.3.1 of the GIA addressing contingencies. However, we will direct MISO to further revise the language in Article 11.3 so that it reads "the Commercial Operation Date for a higher queued interconnection request is delayed, or the project itself is delayed (including due to suspension) such that facilities required to accommodate lower queued projects or the project itself may be altered."

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[259] Supplemental Filing at 23.

192. However, we do agree with E.ON that if a restudy is required, MISO should be required to provide a notice of restudy to the interconnection customer rather than just having the option to do so. Thus, we direct MISO to revise the language in section 8.7 to restore this language to its previous form. We find that this outcome is more consistent with the overall goal of ensuring that all parties are receiving timely and pertinent information about their interconnection projects.

193. We will not direct MISO to provide additional revisions to its proposal regarding the "reach" of the restudy provisions as requested by E.ON. We find that MISO's intent is very clear – projects that require a restudy will be restudied under the terms of the GIP in effect at the time of the restudy.

b. Changes to Point of Interconnection

i. Proposal

194. MISO proposes to move language from section 7.4, which concerns the procedures for conducting the System Impact Study in the System Planning and Analysis phase, into sections 8.3 and 8.5 of the revised GIP, which concern the scope of the System Impact Study and the procedures for conducting the Facilities Study in the Definitive Planning Phase, respectively. This language grants MISO the right to change an interconnection customer's proposed Point of Interconnection if the Interconnection System Impact Study or the Interconnection Facility Study indicate that changing the Point of Interconnection can lower the cost of Network Upgrades without raising the total cost for the Transmission Owner and will not result in a Material Modification. The proposed language in sections 8.3 and 8.5, like the existing language in section 7.4, states that if the interconnection customer chooses to revert back to the original Point of Interconnection, the additional cost of the Network Upgrades will be treated as Transmission Owner's Interconnection Facilities for the purpose of cost allocation and refunds. [260]

ii. Comments

195. A number of parties contend that the proposal gives MISO unilateral authority to modify the interconnection customer's point of interconnection and that it subjects the interconnection customer to unreasonable uncertainty since it may not easily be able to modify its point of interconnection. The Midwest Developers assert that requiring the interconnection customer to make a written request to retain the original point of interconnection and agree that network upgrades will be treated as the Transmission Owner's interconnection facilities allows MISO to eliminate the right of an

[260] Proposed revised sections 8.3 and 8.5.

interconnection customer to be reimbursed for Network Upgrade costs by reclassifying these facilities. They state that MISO has failed to explain why eliminating these reimbursement rights is just and reasonable.[261]

196. EcoEnergy states that MISO's proposal stands in stark contrast to the current tariff, which only allows MISO to make changes to the point of interconnection at the System Impact Study in the System Planning and Analysis phase. EcoEnergy notes that while MISO's proposal will allow it to change the point of interconnection as late as the Facilities Study in the Definitive Planning Phase, interconnection customers must have land control and permits substantially complete by the time the project gets to the Facilities Study under the M3 milestone. EcoEnergy states that while MISO attempts to justify its proposal by stating that it simply intended to allow a point of interconnection change at the Definitive Planning Phase stage and by providing pertinent examples, EcoEnergy argues that it is not unreasonable for MISO to determine the lowest cost point of interconnection during the Feasibility Study or the System Impact Study and that there is no reason why the lowest cost point of interconnection could not be identified earlier in the examples provided.[262]

197. Several parties highlight that changing a point of interconnection is not a minor matter. The Midwest Developers and AWEA and WOW note that changing the point of interconnection can impact various aspects of project development.[263] The Midwest Developers maintain that only interconnection customers should be able to change their point of interconnection since it is the customer that will bear the cost of interconnection facilities. AWEA and WOW add that the Commission should require MISO to encourage cooperation among the relevant parties – instead of unilaterally allowing MISO to change the point of interconnection – and that interconnection customers should have a reasonable veto power over any change to the point of interconnection.[264] NextEra observes that MISO's proposal overlooks the fact that an interconnection customer's chosen point of interconnection may reflect the land acquisition constraints faced by the project developer. NextEra argues that the interconnection customer should be given the right and opportunity to show that it has engaged in reasonable commercial efforts to obtain the rights to access the new point of interconnection and, if it has, then it should be able to remain at the original point of interconnection without incurring

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[261] Midwest Developers Protest at 28-29.

[262] EcoEnergy Protest at 3-5.

[263] Midwest Developers Protest at 29; AWEA and WOW Protest at 37-38.

[264] AWEA and WOW Protest at 38.

additional costs.[265] Iberdrola argues that allowing changes so late in the interconnection process could significantly increase costs and disadvantage the interconnection customer. Iberdrola maintains that the Commission should direct MISO to revise these sections to reference the "existing requirement for Interconnection Customer consent in section 6.3"[266]

198. Alliant expresses support for MISO's revisions to section 8.5. It states that MISO's proposal will allow it to change the point of interconnection where doing so would result in reduced network upgrade costs. According to Alliant, this will protect load in the zones of ITC Midwest and American Transmission Company, where load bears the majority of generator interconnection costs.[267]

iii. Commission Determination

199. Here, MISO proposes to revise the Tariff to grant itself authority to modify the point of interconnection following both the System Impact Study and the Facilities Study in the Definitive Planning Phase. As EcoEnergy correctly points out, currently the Tariff only permits MISO to make changes to the point of interconnection if the System Impact Study in the System Planning and Analysis phase indicates that changing the point of interconnection can lower the cost of network upgrades.[268] While we believe that MISO's proposal to make such a change at the System Impact Study stage is consistent with MISO's proposal to revise the nature of the System Planning and Analysis phase, we find that MISO has failed to justify its proposal to make changes at the Facilities Study stage. The System Impact Study will be the first study conducted after the interconnection customer enters the Definitive Planning Phase. With respect to the Facilities Study, we agree with protesters that allowing MISO to change the point of interconnection at such a late stage could significantly increase costs by impacting

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[265] NextEra Protest at 6-7.

[266] Iberdrola Protest at 22-23. Currently, section 6.3 provides that "[i]f the results of the Interconnection Feasibility Study indicate that an Interconnection Request for a smaller capacity amount could proceed to the [Definitive Planning Phase], Interconnection Customer will have the option to reduce the size of the Interconnection Request to a size equal to or less than Transmission Provider determined amount and proceed to the Definitive Planning Phase." MISO, FERC Electric Tariff, Attachment X (0.0.0), § 6.3.

[267] Alliant Comments at 5.

[268] MISO, FERC Electric Tariff, Attachment X (0.0.0), § 7.4.

aspects of project development other than the point of interconnection and unreasonably disadvantage that interconnection customer. Accordingly, we accept MISO's proposed revisions to section 8.3 concerning the ability to change the point of interconnection at the System Impact Study stage; however, we reject, without prejudice, MISO revisions to section 8.5. regarding MISO's authority to change the requested point of interconnection at the Facilities Study stage. Therefore, we direct MISO to submit a compliance filing, within 30 days of the issuance of this order, deleting this language from section 8.5 of the GIP.

c. Model Sign-Off

i. Proposal

200. MISO states that, as proposed, sections 7.3 and 8.3 of the GIP require the interconnection customer to provide a completed Interconnection Study Model Review Form that is provided as a new Appendix 10 to the GIP. MISO explains that these revisions require each interconnection customer to review and sign off on the model for its study prior to the SIS in both the System Planning and Analysis phase and the Definitive Planning Phase.[269] MISO explains that the failure to provide a form within 30 days is grounds for withdrawal under section 3.6 of the GIP. MISO maintains that requiring the interconnection customer to sign off on the underlying model will help provide additional certainty to the interconnection process. MISO explains that, while it distributes load flow models to Transmission Owners and interconnection customers for review early in the study process under the current GIP, interconnection customers, in practice, rarely raise issues with the model unless the interconnection studies reveal that costly upgrades are necessary to interconnect or when PPAs are scarce.[270] MISO states that interconnection customers will then allege that the study contains modeling errors, which can impact the interconnection process. MISO states that requiring interconnection customers to sign off at the beginning of the process will make the process more efficient by avoiding the need for arguments and to repeat work.[271]

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[269] November 1 Filing at 13, 16; Laverty Testimony at 28.

[270] Laverty Testimony at 28-29.

[271] *Id.* at 31.

ii. Comments

201. Xcel supports the model sign-off requirement. It states that the sign-off requirement on the model will help provide certainty and efficiency to the process and remove delays that currently exist.[272]

202. Several commenters object to the requirement that the interconnection customer submit the Interconnection Study Model Review Form within 30 days and argue that a longer time period is necessary.[273] AWEA and WOW state that while they do not dispute the fact that requiring interconnection customers to sign off on a model might help to reduce model changes and restudies in the future, they believe that 30 days is insufficient because interconnection customers will likely need to hire consultants to assist with this review. AWEA and WOW further state that they believe that the consequences for not returning the sign-off form within 30 days are overly punitive and unnecessary and that other consequences, such as not allowing studies to move forward, would likely be just as effective without the extreme measure of removing an interconnection customer from the queue. The Midwest Developers and AWEA and WOW ask the Commission to direct MISO to change the deadline for reviewing the study model to 90 days and to remove the punitive consequences of withdrawal from the queue if the study model review is not returned in the prescribed time period.[274] Geronimo argues that at least 60 to 90 days would be appropriate.[275]

203. Additionally, the Midwest Developers and Iberdola state that signing off on a study model should not preclude challenges to interconnection studies.[276] The Midwest Developers note that, while interconnection customers will have the opportunity to review the models, they will not have full access to system data available to MISO and Transmission Owners. Thus, the Midwest Developers maintain, that it is not reasonable to equate signing off on a form with signing away one's right to later challenge study results or underlying assumptions. Accordingly, the Midwest Developers ask the Commission to direct MISO to include language in its proposal to the effect that neither an interconnection customer's opportunity to comment on the model nor its execution of

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[272] Xcel Comments at 8.

[273] AWEA and WOW Protest at 28-29, Midwest Developers Protest at 30-31; Geronimo Protest at 3.

[274] AWEA and WOW Protest at 28-29, 31; Midwest Developers Protest at 28.

[275] Geronimo Protest at 3.

[276] Midwest Developers Protest at 28; Iberdola Comments at 23.

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the Interconnection Study Model Review Form constitutes a waiver of its rights to challenge the study results.[277]

204. AMP requests clarification that the provision does not require that the interconnection customer and the Transmission Owner agree on the recommended changes to the model that will be included on the Interconnection Study Model Review Form. It believes the Transmission Owner would have the opportunity to take advantage of the interconnection customer and delay the process in order to ensure that an interconnection customer's project will be withdrawn from the queue[278] E.ON claims that MISO has not demonstrated that there is a systemic problem. It states it is not aware of any lack of necessary information from the interconnection customer in order for MISO to provide accurate study results.[279]

205. AWEA and WOW argue that MISO's proposals to increase the risks and requirements for interconnection customers should be balanced with new accountability for MISO and the MISO Transmission Owners. AWEA and WOW state that there continue to be errors in study models, which delay the progress of interconnection customers; yet, there are no penalties for such errors. They state that, when the model sign-off requirement was discussed early in the stakeholder process, there were consequences if the Transmission Owner did not return the sign-off form. AWEA and WOW argue that Transmission Owners have an important role in ensuring an efficient and accurate interconnection process, as, in many cases, interconnection customers do not have detailed information about the transmission system, other interconnection customer's requirements, or new generators or transmission facilities being added to the system. Accordingly, AWEA and WOW argue that the Commission should require MISO to include balanced consequences for both MISO and the Transmission Owners regarding meeting timelines included in the tariff, inclusion of errors in study models, etc.[280] Similarly, Geronimo argues that MISO's proposal lacks proportionality because, while failure to submit the model-sign off form within 30 days will result in complete withdrawal from the queue, there are no revisions that would hold MISO or the Transmission Owners accountable for any mistakes that they may make.[281]

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[277] Midwest Developers Protest at 28.

[278] AMP Protest at 14.

[279] E.ON Protest at 9-10.

[280] AWEA and WOW Protest at 30-31.

[281] Geronimo Protest at 3.

iii. Answers

206. In response, MISO repeats its arguments in support of the proposed revision. MISO adds that the requirement does not strip interconnection customers of the ability to protest the ultimate results of the Interconnection Study, but rather it merely seeks to engage interconnection customers in the Interconnection Study Process up front so as to ensure that any disagreements over the study results are genuine. MISO also disagrees with the argument that interconnection customers do not have the necessary expertise or resources to be able to review the Interconnection Study Model because it has not seen any lack of resources or expertise on the part of interconnection customers when challenging Interconnection Study results. MISO finally notes that it cannot allow interconnection customers to have additional time to complete the Interconnection Study Model Review Form without a commensurate delay in the Definitive Planning Phase because it only has 90 days to complete the Interconnection Study.[282]

iv. Commission Determination

207. We conditionally accept MISO's proposed revisions to sections 7.3 and 8.3 of the GIP.

208. We disagree with NextEra's contention that 30 days is insufficient time for the customer to review and execute a study review form when it is being studied in the Definitive Planning Phase. Before reaching the Definitive Planning Phase, a customer would have had to perform its own due diligence in order to build a business case that would justify its request for interconnection and would have committed to move forward. Part of this due diligence would be to understand the impact of the proposed interconnection on the existing transmission system with the interconnection request. Another part would be lining up appropriate technical experts or consultants. This would be done through its own efforts and by the customer availing itself of MISO's Pre-Queue Phase and Interconnection Feasibility Study (section 6 of the GIP). Thus, we expect that the interconnection customer would be sufficiently knowledgeable regarding the state of its interconnection request such that 30 days is sufficient for the customer to seek out and understand any differences between its knowledge and the model provided by MISO.

209. We also disagree that deeming the interconnection request to be withdrawn for failing to fulfill the obligation to execute an Interconnection Study Model Review Form within 30 days in the Definitive Planning Phase is not just and reasonable or is unduly harsh. As the Commission has stated previously, the overall goal of interconnection queue reform is to discourage speculative or unviable projects from entering the queue, getting projects not making progress towards commercial operation out of the queue, and

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[282] MISO December 15 Answer at 12-13.

helping viable projects achieve commercial operation as soon as possible.[283] Customers that are insufficiently prepared to meet this obligation within the given timeframe are not making sufficient progress towards reaching commercial operation and therefore, should not remain in the interconnection queue.

210. Finally, with respect to AMP's concern regarding the potential for a Transmission Owner to delay the process in order to ensure that an interconnection customer's project will be withdrawn, we note that the language of proposed sections 7.3 and 8.3 does not appear to require the interconnection customer and Transmission Owner to agree on a model within 30 days. On the contrary, these sections require the interconnection customer to submit a completed and executed Interconnection Study Model Review Form within 30 days of receiving the models.

211. However, we find that MISO has not adequately explained why the interconnection customer should be required to return the Interconnection Study Model Review Form within 30 days in the System Planning and Analysis phase. Given MISO's proposal that an interconnection customer may remain in the System Planning and Analysis phase until it is ready and that the interconnection customer can set assumptions under which it is studied in the System Planning and Analysis phase, we believe the that same rigorous 30 day period has not been supported as just and reasonable. We will require MISO to submit a compliance filing revising this section to propose a timeframe that is in line with the fact that the interconnection customer may remain in the System Planning and Analysis phase indefinitely.

6. Modifications

a. MISO's Proposal

212. MISO proposes to revise section 4.4 of the GIP to limit the number of permissible modifications once a project enters the Definitive Planning Phase. More specifically, MISO states that it proposes to limit the types of permissible modifications to those listed in sections 4.4.1, 4.4.2, and 4.4.4. MISO states that an interconnection customer would still be required to provide an analysis demonstrating why the proposed change is not a material modification.[284]

213. MISO explains that the only changes that would be permitted during the Definitive Planning Phase under section 4.4.1 would be changes to the technical parameters associated with the Generating Facility technology (i.e., wind turbines) and changes to

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[283] Queue Reform Order, 124 FERC ¶ 61,183 at P 44.

[284] November 1 Filing at 9.

the Point of Interconnection permitted under section 4.4.[285] In new section 4.4.2, MISO proposes language that prohibits modifications to the type of interconnection service selected by the interconnection customer after the project enters the Definitive Planning Phase other than a change from Network Resource Interconnection Service to Energy Resource Interconnection Service pursuant to section 3.2 of the GIP.[286] Section 3.2 of the GIP states that an interconnection customer requesting Network Resource Interconnection Service may request that it be concurrently studied for Energy Resource Interconnection Service up to the point when the Facilities Study for network upgrades commences. At that point, an interconnection customer may elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

214. Additionally, MISO states that it is adding language to section 4.4.4 providing that extensions to the In-Service Date or Commercial Operation Date of the Generating Facility shall be deemed a Material Modification.[287]

b. <u>Comments</u>

215. E.ON notes that while MISO indicates that "changes to technical parameters" includes changes in turbines, section 4.4.1 does not mention turbines. E.ON requests that the Commission require MISO to clarify this language to reflect that a change in turbines is a permissible modification. Additionally, E.ON states that the requirement that the interconnection customer provide a "detailed analysis" demonstrating that the change in turbines is not a Material Modification should be revised, as MISO itself recognizes that it has never denied a request to change turbines and MISO has tremendous experience and familiarity of the system impact that a change in turbines has. E.ON suggests that the section be revised to read that "no such detailed analysis shall be required so long as a change in turbines involves the type or manufacturer of turbines Transmission Provider

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[285] Proposed revised section 4.4 states that, prior to the completion of the interconnection studies, the interconnection customer, Transmission Owner, or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits of the interconnection. To the extent the changes are acceptable to all parties, such acceptance not to be unreasonably withheld, MISO shall modify the point of interconnection and/or configuration

[286] November 1 Filing at 9.

[287] *Id.*

maintained on its approved list." E.ON argues that this revision would be consistent with MISO's goals of improving operating efficiency and customer service.[288]

216. Iberdrola argues that the Commission should reject MISO's attempt to shift Transmission Provider responsibilities to interconnection customers. It states that MISO has failed to support the proposed limitation on modifications once a project is in the Definitive Planning Phase and that MISO should be required to evaluate project modifications on a case-by-case basis to determine their impact on lower-queued projects. Iberdrola maintains that the interconnection customer should have the opportunity to demonstrate that a modification does not have any material impact on a later queued project.[289]

217. Similarly, EPSA argues that the Commission must reject MISO's proposal to restrict the scope of permissible modifications in the Definitive Planning Phase, as MISO has failed to justify the need for these restrictions and MISO's proposal would upset the balance struck by Order No. 2003 between providing customers with flexibility and ensuring the Transmission Providers can efficiently and accurately process interconnection requests. EPSA states that MISO has failed to justify its determination that the only plant equipment that may be changed in the Definitive Planning Phase is the generator turbine or its decision to eliminate other changes that the Commission determined to be permissible and non-material in Order No. 2003, such as reductions in the size of the proposed facility. Additionally, EPSA argues that MISO has no basis for its blanket presumption that, apart from changes to generation turbines, any such changes will necessarily materially affect lower-queued generators. EPSA states that the Commission should require MISO to continue to examine whether a proposed change has a material impact on lower-queued generators on a case-by-case basis.[290]

218. Midwest Developers argue that an interconnection customer should have the right to change from Network Resource Interconnection Service to Energy Resource Interconnection Service after the Facilities Study if a restudy indicates that Network Resource Interconnection Service would require additional Network Upgrades to be built.[291]

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[288] E.ON Protest at 25-27.

[289] Iberdola Protest at 21-22.

[290] EPSA Protest at 18-20.

[291] Midwest Developers Protest at 37.

219. Several parties argue that the Commission should reject MISO's proposal regarding changes to the commercial operation and In-Service Dates. A number of parties argue that MISO's proposal is contrary to Commission precedent stating that extensions of more than three years do not constitute Material Modifications unless it can be demonstrated that the proposed extension would harm lower-queued interconnection customers or otherwise harm reliability.[292] AWEA and WOW maintain that MISO is treating all extensions to commercial operation and In-Service Dates as suspensions in order to justify the implication that any extension is a per se Material Modification. AWEA and WOW state that the Commission has rejected such attempts in the past.[293] They urge the Commission to clarify that MISO may not summarily deny extensions to an interconnection customer's Commercial Operation Date, In-Service Date, or other milestones.

220. E.ON argues that MISO has failed to provide any support for its proposal regarding extensions of the commercial operation and In-Service Dates and that this revision is not necessary to advance queue reform or to address any backup. With respect to extensions of the In-Service Date, this date, by definition, is the date that the interconnection customer expects to use the Transmission Owner's interconnection facilities to obtain back feed power. E.ON states that, as a result, extending this date will not impact other projects in the queue and will not contribute to any backlog in the queue. Likewise, E.ON claims that an extension of the Commercial Operation Date will not impact the generation queue because the Transmission Owner will construct the network upgrades agreed upon and, with the network upgrades in place, any lower-queued generator will not be impacted. Moreover, E.ON states that lower-queued generators will not be harmed if a higher-queued facility achieves commercial operation at a later date because the studies of lower-queued generators are required to model higher-queued generating facilities.[294]

221. Further AMP protests that an interconnection customer should not be penalized for circumstances beyond its control that may change the In-Service or commercial operation date. AMP states that MISO's elimination of the ability to change the In-Service and commercial operation date would force the interconnection customer to

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[292] EPSA Protest at 18 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 130 FERC ¶ 61,172, at P 13 (2010); *Judith Gap Energy LLC*, 125 FERC ¶ 61,169, at PP 17-20 (2008); *Ill. Power Co.*, 120 FERC ¶ 61,237, at PP 20-22 (2007)); AWEA and WOW Protest at 32; Midwest Developers Protest at 30-32.

[293] AWEA and WOW Protest at 32-35 (citing *Quilt Block Wind Farm*, 130 FERC ¶ 61,172 (2010)).

[294] E.ON Protest at 27-28.

incorporate extra time into projected In-Service and commercial operation dates as a cushion against the inability to alter these dates in the future.[295] Iberdrola also raised the concern that the proposed revisions prevent the interconnection customer from modifying its commercial operating date even in the event that circumstances dictate that network upgrades or interconnection facilities will take significantly longer than anticipated.[296]

c. Answers

222. MISO explains that the purpose of these changes is to provide all queued projects with certainty that only projects that are ready to proceed to commercial operation enter the Definitive Planning Phase. MISO argues that EPSA's argument that an interconnection customer should not be required to forfeit its place in the queue for extending its Commercial Operation Date fails to consider that there are already provisions in place in the GIA to accommodate minor construction delays over which the interconnection customer has no control.[297] Finally, MISO notes that a delay of three years would negate the Facilities Study for the project and would require a restudy in the System Planning and Analysis phase.[298]

d. Commission Determination

223. We conditionally accept MISO's proposed revisions to section 4.4. We believe that MISO's proposal to limit the types of change permissible in the Definitive Planning Phase is consistent with the need to ensure that a project that enters the Definitive Planning Phase is "definitive." We understand Iberdrola's concern that MISO may seek to remove projects from the queue because of minor modifications, although we note that parties have a right to contest such actions through the dispute resolution procedures in the GIP and as a backstop, at the Commission. However, we will require further modifications below.

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[295] AMP Protest at 4-5.

[296] Iberdola Protest at 22.

[297] MISO December 15 Answer at 9-10 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 135 FERC ¶ 61,222, at P 26 (2011) (explaining that Article 5.1.1 of the GIA contemplates that circumstances may arise where construction milestones will not be met and provides for the possibility that construction timelines may need to be modified)).

[298] *Id.* at 10.

224. We decline to require MISO to revise the language of section 4.4.1 to clarify that a change in turbine is a permissible modification. While MISO acknowledges that it has not found an instance where it has not granted a request for a turbine change, we are not persuaded that we should require MISO to revise this section to permit turbine changes on a generic basis. Instead, we believe that MISO should continue to have the ability to evaluate each proposal to change the technical parameters associated with a Generating Facility's technology, including a turbine change, to ensure that the proposed modification is not a Material Modification.[299]

225. However, with regard to MISO's proposed revisions regarding the Commercial Operation Date and In-Service Date, we find that further modification is required. Specifically, we find that where a party to the GIA other than the interconnection customer changes its milestones thereby resulting in the interconnection customer needing to revise its own Commercial Operation Date and In-Service Date, we believe that MISO's approval of such revision should not be unreasonably withheld. Similarly, MISO's approval of an interconnection customer's need to change a date due to changes in a higher-queued interconnection request should not be able unreasonably withheld. In either case, these changes should not exceed three years beyond the original Commercial Operation Date or In-Service Date. We direct MISO to include in its compliance filing revisions to section 4.4, within 30 days of the date of this order, consistent with this discussion.

226. With respect to the Midwest Developers' argument that an interconnection customer should be permitted to downgrade its level of interconnection service after the Facilities Study if a restudy indicates that Network Resource Interconnection Service would require additional upgrades to be built, we disagree. We believe that MISO's proposal is just and reasonable and consistent with the purpose of the Definitive Planning Phase. While the Midwest Developers identify an alternative that they prefer, this alone does not render MISO's proposed revisions unjust and unreasonable.

7. Miscellaneous

a. Article 5.9

i. Proposal

227. MISO proposes to revise Article 5.9, "Limited Operation," of the *pro forma* GIA to require the maximum permissible output of a generating facility to be updated on a quarterly basis in the event that the network upgrades necessary for the interconnection of the generating facility are not in service within six months following the Commercial

[299] Proposed revised section 4.4.1.

Operation Date of the facility. MISO explains that this process is currently used for provisional GIAs executed pursuant to section 11.5 of the GIP. MISO states that its proposal will extend this practice to all GIAs that may have limited operation until all upgrades are in place.[300]

ii. Comments

228. In its protest, NextEra argues that MISO is proposing to establish stricter operating limits on projects that are already operating but whose Network Upgrades are not yet completed. NextEra explains that under the current version of Article 5.9, MISO performs operating studies to determine to what extent a project without all of the required upgrades in place may operate and develop operating guides based on this information. Here, according to NextEra, MISO's proposed language is designed to produce a single limit which will be applied across all hours in a given quarter, regardless of the dynamic nature of the system or the output of a wind energy generator. NextEra alleges that this provision will severely limit generators with executed GIAs to an inflexible operating cap that unnecessarily restricts operations.[301]

229. EcoEnergy argues that if this section is adopted, the manual curtailment that has been conducted in real time will be replaced with a quarterly curtailment study that may restrict sales that could have been conducted under previous procedures. EcoEnergy states that there has long been a lack of transparency in the wind curtailment process and this language will only make the situation worse.[302]

iii. Commission Determination

230. In the Queue Reform Order, the Commission agreed with MISO that as the number of temporary (now known as provisional) interconnections increase that it would become impractical for MISO to calculate operating limits based on real-time conditions.[303] Here, MISO is proposing to apply the same type of operating limits on projects that are not yet capable of obtaining their maximum output because the upgrades necessary to facilitate that maximum output are not yet completed. We find that the burden that would be imposed on MISO in order to provide real-time operating limits in these two situations is analogous. Thus, we will allow MISO to provide quarterly

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[300] November 1 Filing at 19.

[301] NextEra Protest at 8-9.

[302] EcoEnergy Protest at 3-4.

[303] Queue Reform Order, 124 FERC ¶ 61,183 at P 131.

operating limits to generators that are operating, but are unable to operate at their full capacity, because they are still waiting for network upgrades to be constructed.

b. Appendix H

i. Proposal

231. MISO proposes to add new Appendix H to the GIA to incorporate *pro forma* language to be used for provisional GIAs. MISO states that the language has been developed based on MISO's experience in implementing provisional GIAs and that it intends to include Appendix H as part of all provisional GIAs on a prospective basis.

ii. Comments

232. MISO Transmission Owners state that in the third line of the second paragraph, the language "and to require then to be in place" should read "and to require them to be in place."

iii. Supplemental Filing

233. In the Supplemental Filing, MISO notes that the reference to "Interconnection Customer facilities" in paragraph 3 of its revisions to Appendix H is meant to encompass Network Upgrades, Interconnection Facilities, Distribution Upgrades, System Protection Upgrades, and/or Generator Upgrades. MISO states that it will clarify this language if so directed by the Commission.[304]

iv. Commission Determination

234. We direct MISO to revise, within 30 days of the date of this order, the third line of the second paragraph of Appendix H to the GIA as described by MISO Transmission Owners above. Additionally, we direct MISO to clarify the language in Appendix H regarding the usage of "Interconnection Customer facilities" as proposed in its Supplemental Filing. In particular, we direct MISO to clarify that the reference to "Interconnection Customer facilities" in paragraph three of its revisions to Appendix H is meant to encompass Network Upgrades, Interconnection Facilities, Distribution Upgrades, System Protection Upgrades, and/or Generator Upgrades.

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[304] Supplemental Filing at 27.

c. Dispute Resolution

i. Proposal

235. MISO proposes to delete the reference to dispute resolution as an alternative to the execution or unexecuted filing of a GIA. MISO states that because projects may now remain in the System Planning and Analysis phase until they are ready to proceed and that they will have to make a financial commitment to meet the M2 milestone payment, MISO anticipates that projects that reach this stage will not need to seek dispute resolution. Further, MISO states that providing dispute resolution as an alternative to proceeding with a GIA or multi-party facilities construction agreement in executed or unexecuted form at that late stage injects uncertainty into the interconnection process. Finally, MISO states that it has seen an increase in requests for dispute resolution and critiques of its process as projects near the deadline to execute an agreement or to file it unexecuted. And in any case, MISO notes that dispute resolution is still available to parties but that seeking dispute resolution does not delay the deadline to execute the agreement or file it unexecuted.

ii. Comments

236. Midwest Developers argue that MISO's proposal effectively eliminates dispute resolution as a meaningful option for interconnection customers by eliminating the "tolling" of the sixty day deadline while such dispute resolution is pending.[305] While MISO states that dispute resolution would still be available to customers, Midwest Developers aver that dispute resolution regarding the draft GIA is of little value if interconnection customers nonetheless have to choose, prior to completion of the dispute resolution process, whether to execute the GIA or request that it be filed unexecuted. As a result, Midwest Developers posit that the only effect of MISO's proposal would be to decrease the likelihood of resolving the underlying problems that trigger dispute resolution and to increase the number of unexecuted GIAs filed at the Commission.[306]

iii. Commission Determination

237. We will accept MISO's proposal to eliminate the reference to dispute resolution as an alternative to the execution or unexecuted filing of a GIA. While we do not disagree with Midwest Developers that the result of this change is to eliminate the "tolling" of the sixty day deadline, we find MISO's general argument regarding the timeliness of this queue reform filing compelling. That is, we agree with MISO that there are numerous

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[305] Midwest Developers Protest at 35.

[306] *Id.* at 36.

projects entering the Definitive Planning Phase without moving forward while the developers attempt to resolve uncertainties or to obtain financing[307] and that this outcome is inconsistent with the Commission's goal of improving the efficiency of the interconnection process.

d. GIP, Appendix 1

i. Proposal

238. MISO proposes to revise Attachment A to Appendix 1 of the GIP to request additional detail related to reactive capability for wind turbines and other details, including specific MVAR data for the turbines and the MVAR data provided by the collector cables between the generator turbines and the point of interconnection, to assist in the evaluation of interconnection requests. Under MISO's proposal, an interconnection customer is required to provide this information prior to entering the Definitive Planning Phase.[308] MISO states that, consistent with Order No. 661,[309] interconnection requests for wind resources need not supply the reactive power information at the time that they submit their application but do need to supply this information before entering the Definitive Planning Phase.[310]

ii. Comments

239. The Midwest Developers argue that the Commission should direct MISO to revise the requirement to provide MVAR data prior to entry into the Definitive Planning Phase because MISO has failed to explain why it needs this information prior to entering the Definitive Planning Phase and because accurate MVAR data cannot be provided this early in the development stage. Moreover, they state that MISO's proposal is inconsistent with Order No. 661, which does not impose a power factor requirement on wind facilities unless and until the Transmission Provider shows, through the System Impact Study, that it is required to ensure the safety or reliability of the Transmission Provider's transmission system. They note that the System Impact Study occurs during the Definitive Planning Phase and that, by requiring this information from wind projects in order to enter the Definitive Planning Phase, MISO proposes to compel wind projects

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[307] MISO December 15 Answer at 5.

[308] Proposed revised section 8.2.

[309] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[310] November 1 Filing at 18; Proposed revised Appendix 1, Attachment A.

to demonstrate their ability to provide this capability even before MISO has demonstrated that it will be required.[311]

240. Similarly, AWEA and WOW argue that an interconnection customer cannot provide all of the data called for on pages 4 and 5 of Attachment A to Appendix 1 of the GIP with 100 percent accuracy at the outset of the GIP. For example, AWEA and WOW state that the MVAR provided by the collector cables between the generator turbines and the Point of Interconnection depends on the design and construction-specific details that will be available later in the process. AWEA and WOW state that, while an estimate can be provided at the time the form is submitted, this will likely need to be adjusted later. Additionally, AWEA and WOW state that the Operational Tap Setting, on the other hand, is impossible to determine at the outset of the Definitive Planning Phase, and should be removed from the form. AWEA and WOW believe that interconnection customers can provide reasonable estimates to most of the information requested on the form at that time, but are concerned that the stringent limitations on modifications under the tariff could result in an interconnection customer being withdrawn from the queue in the later stages of the Definitive Planning Phase.[312]

iii. Answers

241. In its answer, MISO explains that its proposal is intended to ensure that any need for reactive power can be determined in the System Impact Study is consistent with Order No. 661. MISO asserts that information from interconnection customers is necessary to make this determination. Finally, MISO states that to the extent this information is truly unavailable early in the process, MISO would consider that issue on a case-by-case basis.[313]

iv. Commission Determination

242. We reject MISO's revisions to require detail related to reactive power capability for wind turbines prior to entering the Definitive Planning Phase. We agree with Midwest Developers that MISO's proposal is inconsistent with Order Nos. 661 and

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[311] Midwest Developers Protest at 38-39.

[312] AWEA and WOW Protest at 35-36.

[313] MISO December 15 Answer at 12 n.21.

661-A.[314] The Commission's policy requires that if a System Impact Study demonstrates that a wind plant must possess reactive power capability that wind plant must be capable of meeting the standard power factor range of 0.95 leading to 0.95 lagging or any different power factor range that has been established for the relevant control area.[315] MISO's proposed revisions regarding reactive power capability – by requiring this information before any need has been established by a System Impact Study - puts the cart before the horse. Otherwise, we accept the informational requirements to Attachment A to Appendix 1 of the GIP and require that MISO submit a compliance filing within 30 days of the date of this order removing the requirement to provide reactive power information prior to entering the Definitive Planning Phase.

243. In response to AWEA and WOW's argument that an interconnection customer cannot provide all of the data needed, we recognize the concern of only being able to provide an estimate of data and potentially being withdrawn from the queue if modifications are needed. Therefore, we will require MISO, in a compliance filing to be submitted within 30 days from the date of this order, to revise its Tariff to accommodate the fact that the customer may only be able to provide estimates of the details described on pages 4 and 5 of Attachment A to Appendix 1 and ensuring that an interconnection customer will not be removed from the queue if adjustments are needed.

e. Site Control

i. Proposal

244. In its revisions to the GIP and the GIA, MISO proposes to expand the definition of Site Control by requiring interconnection customers to demonstrate a right to develop a site for the construction of interconnection facilities in addition to the same demonstration for generating facilities.

ii. Comments

245. In its protest, Iberdrola argues that MISO's proposed definition of Site Control is overly vague because the phrase "when applicable" when applied to interconnection

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[314] The Commission will hold a Technical Conference to examine whether the Commission should reconsider or modify the reactive power provisions of Order No. 661-A. *See* Notice of Technical Conference, Docket No. AD12-10-000 (Feb. 17, 2012).

[315] *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,270 (2006), *order on reh'g,* 135 FERC ¶ 61,065 (2011).

facilities is insufficiently specific as to when site control will be applicable and that, as proposed, leaves too much discretion to MISO.

iii. Commission Determination

246. We agree with Iberdrola that MISO's proposed definition is unclear. Therefore, we will accept MISO's proposed revisions to the definition of Site Control on the condition that MISO include in its compliance filing revisions to clarify those instances where the documentation required to demonstrate site control includes Interconnection Facilities.

f. Section 7.5

i. Proposal

247. MISO proposes to change the meeting between the interconnection customer, Transmission Owner, and MISO following the receipt of the Interconnection System Impact Study report from a mandatory meeting to an optional meeting that will be held if needed.[316]

ii. Comments

248. AMP states that in the event the Commission does not reject this change, the Commission should direct MISO to further modify the language in section 7.5 to state that whether to hold a meeting is within the interconnection customer's discretion and that the Transmission Owner and MISO must participate in good faith if an interconnection customer determines that a meeting is necessary.[317]

iii. Commission Determination

249. We conditionally accept MISO's proposed revision to section 7.5 of the GIP regarding the meeting to discuss the outcome of the Interconnection System Impact Study. We recognize that a meeting may not be necessary in all cases. However, we find that all parties should have an opportunity to discuss the outcome of the Interconnection System Impact Study to raise issues with the outcome of the study and that other parties should participate in good faith. Therefore, we direct MISO to revise section 7.5 to state that the interconnection customer, Transmission Owner and/or the Transmission Provider may request such a meeting and that all parties must participate in such meetings in good faith. .

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[316] November 1 Filing at 14.

[317] AMP Protest at 15.

g. Study Backfill

i. Proposal

250. In section 4.2 of the GIP, MISO proposes to delete the last paragraph of the section that related to "backfilling" interconnection customers in group studies.[318] Based on its experience, MISO states that few interconnection customers want to have their projects moved forward in the process to "backfill" a study when a higher-queued project withdraws.[319]

ii. Comments

251. The Midwest Developers argue that eliminating MISO's authority to "backfill" a study is neither necessary nor prudent. They contend that MISO has missed opportunities to solicit backfill projects by not providing timely and useful information to potential backfill projects. They state that the fact that MISO has ineffectively implemented the backfill provisions should not be interpreted to mean that the provisions are not desirable or useful.[320] Additionally, Midwest Developers believe that backfilling projects could become more useful as the Group 5 restudy process is completed. Similarly, ARES argues that MISO has discouraged and disregarded requests for backfill provisions and suggests that the backfill provision should remain in the Tariff.[321]

iii. Commission Determination

252. We deny, without prejudice, MISO's unsupported proposal to eliminate the study backfill provisions of section 4.2 and direct MISO, within 30 days of the date of this order, to restore this language to section 4.2. While MISO maintains that few interconnection customers have wanted to be considered for being backfilled into a group study, we still agree with MISO's original argument in the Queue Reform Order that "'backfilling' of group studies should reduce the restudy time and increase cost certainty

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[318] Backfilling occurs when a project withdraws from a group study and MISO substitutes the next highest queued, similarly situated interconnection request into the study group.

[319] November 1 Filing at 9.

[320] Midwest Developers Protest at 40.

[321] ARES Protest at 1.

for all members of the group."[322] MISO has not provided any evidence that these provisions need to be removed or that retaining these provisions causes any harm.

8. Net Zero Interconnection Service

a. Proposal

253. In section 3.2.3 of the GIP, MISO proposes a new class of Energy Resource Interconnection Service called Net Zero Interconnection Service. MISO defines Net Zero Interconnection Service as "a form of Energy Resource Interconnection Service that allows an Interconnection Customer to alter the characteristics of a Generating Facility in Commercial Operation, with the consent of Interconnection Customer for that existing Generating Facility, at the same [point of interconnection] such that the new MW capability remains the same."[323] MISO explains that the existing generator and new generator work out a control scheme to regulate the output of the combined unit and, as a result, the net effect on output seen by the system is unchanged.[324]

254. According to MISO, Net Zero Interconnection Service is consistent with Order No. 2003 because it enables existing generators to better use their existing rights to capacity on the transmission system. In support of its proposal, MISO states that the Commission previously approved the creation of conditional Energy Resource Interconnection Service and Network Resource Interconnection Service as a means to enhance the use of existing system capacity.[325]

255. MISO explains that, under its proposal, an interconnection customer that is not the owner or a subsidiary of the owner of the existing Generating Facility will be required to execute an Energy Displacement Agreement with the owner of the existing Generating Facility before submitting a request for Net Zero Interconnection Service. Additionally, the interconnection must also include a memorandum of understanding with the Transmission Owner to enter into a Monitoring and Consent Agreement upon execution of a GIA in its request for Net Zero Interconnection Service.[326]

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[322] Queue Reform Order, 124 FERC ¶ 61,183 at P 112.

[323] Proposed revised section 1.

[324] November 1 Filing at 6; Laverty Testimony at 37.

[325] November 1 Filing at 6 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 61,306, at PP 2-3, 29-32 (2006)).

[326] Proposed revised section 3.3.1; Laverty Testimony at 37-38.

256. MISO states that in order to obtain Net Zero Interconnection Service, the Net Zero Interconnection Service customer must be studied for issues relating to reactive power, short circuit/fault duty, and stability. These studies will identify the interconnection upgrades, if any, that are necessary to address reliability issues associated with the request for Net Zero Interconnection Service.

257. MISO explains that while it believes that the ability to process a request for Net Zero Interconnection Service already exists in the tariff, it is proposing revisions because a critical mass of stakeholders convinced it that it would be beneficial to enumerate and clarify the services in the tariff.[327]

b. Comments

258. Numerous parties filed comments supporting Net Zero Interconnection Service. A number of parties express support for Net Zero Interconnection Service because they believe that it promotes the more efficient use of existing interconnection capacity and will allow interconnection customers to avoid costly upgrades.[328] Xcel asserts that Net Zero Interconnection Service is consistent with the Commission's practice of permitting several generators to use the same point of interconnection even though the generators are separately owned and that Net Zero Interconnection Service will expand opportunities for renewable generation development in MISO.[329] AWEA and WOW add that, given that MISO's transmission system is close to capacity, Net Zero Interconnection Service will act as a bridge strategy for increased development of wind and other types of generation until such time as more local and regional transmission upgrades (e.g., MVPs) can be built.[330]

259. Other parties argue that the Commission should reject Net Zero Interconnection Service because MISO's proposal is unduly discriminatory and not transparent. EPSA claims that MISO's proposal would permit a generation owner to favor itself or an affiliate in obtaining interconnection service because it is the incumbent generation owner, not MISO, which gets to reassign existing interconnection capacity. Nothing in MISO's proposal, EPSA avers, compels the existing generator to reassign its capacity in

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[327] Laverty Testimony at 36-37.

[328] Xcel Comments at 7; Midwest Developers Protest at 43-44; AWEA and WOW Protest at 40.

[329] Xcel Comments at 6-7.

[330] AWEA and WOW Protest at 40.

a transparent or non-discriminatory manner.[331] Similarly, EcoEnergy argues that MISO's proposal allows an incumbent generator to "transfer" interconnection capacity to a generator of its choice, thereby allowing the favored generator to jump over other projects in the queue and avoid funding network upgrades.[332] EcoEnergy asserts that the arrangements for the provision of Net Zero Interconnection Service are neither transparent nor open to competition.[333] EcoEnergy further maintains that MISO's proposal is unduly discriminatory in that it will allow net zero customers to rely upon Special Protection Systems in lieu of paying for network upgrades.[334]

260. The Joint Protestors raise similar concerns and argue that the net zero interconnection at issue in Docket No. ER12-188-000 provides an example of how MISO's proposed Net Zero Interconnection Service is discriminatory and inconsistent with open access.[335] They state that, in order to vary the *pro forma* OATT, MISO must show that its variations are "consistent with or superior to" their *pro forma* OATT and that MISO has failed to provide evidence that its proposal meets this standard – other than bald assertions about the supposed benefits of Net Zero Interconnection Service. In fact, they claim that MISO's proposal cannot meet this burden because it invites discriminatory treatment and eliminates open access by allowing entities with an interest in market outcomes the ability to unilaterally select, in a non-transparent manner, favored new generators in a manner that bypasses the traditional interconnection queue and avoids responsibility for network upgrades.[336] Joint Protestors also argue that, under the Net Zero construct, it would be possible for an uneconomic existing generator to

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[331] EPSA Protest at 27.

[332] EcoEnergy Protest at 10-11.

[333] *Id.*

[334] *Id.* at 12.

[335] Joint Protestors Protest at 25-27, 28-31. In that proceeding, MISO filed a provisional non-conforming GIA among itself, Northern States Power Company and Prairie Rose including a request for Net Zero Interconnection Service. The Commission conditionally accepted the GIA in an order issued December 23, 2011, subject to a further order. *Midwest Indep. Transmission Sys. Operator, Inc*., 137 FERC ¶ 61,234 (2011). In an order issued concurrently with this order, the Commission directs that that GIA be subject to the outcome of certain compliance requirements detailed herein. *Shetek Wind Inc., Jeffers South, LLC and Allco Renewable Energy Limited v. The Midwest Independent System Operator, Inc.*, 138 FERC ¶ 61,250 (2012).

[336] Joint Protestors Protest at 16-20.

essentially shutter its operation and transfer its interconnection capacity to a new generator that it owns or controls, allowing that new generator to interconnect without having to follow the requirements of the GIP applicable to other generators seeking interconnection. Furthermore, Joint Protestors argue that vertically integrated utilities can use Net Zero Interconnection Service to avoid having their baseload generators exposed to market competition, thus creating a disincentive for incumbent public utilities to build more transmission capacity.[337]

261. The Joint Protestors also claim that MISO's net zero policy is inconsistent with open access because it provides an existing public utility with the ability to circumvent the Commission's requirement that each public utility that owns, controls, or operates facilities used for the transmission of electric energy must have on file with the Commission a tariff of general applicability for transmission services over such facilities.[338]

262. The Joint Protestors argue that Net Zero Interconnection Service will harm the development of renewables because independent renewable developers will not be able to compete on an equal footing with generators that are affiliated with existing generators and able to access Net Zero Interconnection Service. Joint Protestors argue that, despite MISO's claims to the contrary, Net Zero Interconnection Service will come with deliverability. They note, for example, that Northern States Power has stated to the Minnesota Public Utilities Commission that it will not see curtailment of its net zero interconnection at issue in Docket No. ER12-188-000 because the existing generating facility is deliverable as a network resource and that status is extended to the Net Zero interconnection generator. Joint Protestors argue that this is a huge advantage because other wind projects will be forced to manage the remaining Energy Resource Interconnection Service as a Dispatchable Intermittent Resource. Finally, Joint Protestors aver that the new Dispatchable Intermittent Resource rules that the Commission recently approved will ensure that non-Net Zero projects will be non-competitive versus Net Zero projects.[339]

263. Joint Protestors argue that MISO's proposal is inconsistent with section 205 in that the tariff filing fails to include the *pro forma* Energy Displacement Agreement and fails to address other agreements that may affect the GIA for a generator receiving Net Zero

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[337] *Id.* at 34-35.

[338] *Id.* at 27-28.

[339] *Id.* at 35.

Interconnection Service.[340] Joint Protestors contend that because the proposed Energy Displacement Agreement establishes specific services, rules, terms, and conditions for Net Zero Interconnection Service, MISO must file a *pro forma* Energy Displacement Agreement with the Commission. Additionally, Joint Protestors argue that MISO's filing does not include a transparent method to determine what the "study limit" of the existing generator is and argues that evidence of the study limit should be required to be included in the *pro forma* GIA. Moreover, Joint Protestors argue that MISO's filing fails to address material issues that could arise that would be unique to Net Zero Interconnection Service, such as, for example, what would happen to the Energy Displacement Agreement in the event of bankruptcy.[341] Additionally, Joint Protestors posit that the GIA for a new generator constitutes an amendment to the terms of the existing generator's GIA and therefore, should require an amendment to the existing generator's GIA.

264. Commenters also raise operational concerns. EPSA states that in its responses to the Commission's data request in the Net Zero Complaint proceeding,[342] MISO implicitly concedes that it does not have the ability to automatically curtail or otherwise prevent the combined output of the new and existing interconnection customers from exceeding the maximum injection limits specified in the existing generator's GIA. Additionally, EPSA contends that MISO will not actively monitor generators operating under Net Zero Interconnection Service in order to identify and sanction net output violations. Finally, EPSA argues that as a consequence of MISO's inability or unwillingness to monitor these arrangements, it is possible that MISO may need to curtail or redispatch other generators to address any overloads caused by generators with Net Zero Interconnection Service.[343]

265. EcoEnergy argues that, despite MISO's contentions that its currently effective tariff allows Net Zero Interconnection Service and that the new provisions proffered here are merely a clarification of the existing tariff, Net Zero Interconnection Service does not currently exist in MISO's Tariff. To the contrary, EcoEnergy states that Section 3.2 of the GIP clearly identifies Energy Resource Interconnection Service and Network Resource Interconnection Service as the only two types of interconnection service available for new interconnection requests. Additionally, EcoEnergy argues that the proposed study requirements for Net Zero interconnection requests and non-Net Zero

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[340] *Id.* at 12-13.

[341] *Id.* at 13-14.

[342] Midwest Indep. Transmission Sys. Operator, Inc., Response to Data Request, Docket No. EL11-53-000 (filed Nov. 7, 2011).

[343] EPSA Protest at 26-27.

interconnection requests are substantially different and that the requirements for net zero requests are inconsistent with the currently effective provisions of GIP sections 3.2.1.2 and 4.1 as well as MISO's Generator Interconnection Business Practices Manual section 4.2.5.[344]

266. According to Joint Protestors, MISO's Net Zero Interconnection Service is premised on the fact that the combined output of the existing generator and the new generator would be limited to the study limit of the existing generator. However, Joint Protestors allege that this premise pre-supposes that the existing generator was properly studied in the first instance and that the study included a review of the interconnection capacity that the existing generator wishes to assign.[345] Joint Protestors argue that the proposed GIA currently before the Commission in Docket No. ER12-188-000 shows that this is not the case. Specifically, they allege that the existing generator in that proceeding was, at best, only partially studied for off-peak conditions but that the filed GIA allows the new generator to utilize these off-peak times under the same parameters of the existing generator during peak times. Joint Protestors contend that in those circumstances, it is not clear that there is off-peak transmission capacity available to be assigned to the new generator.

267. Joint Protestors also contest MISO's assertions that Net Zero Interconnection Service will lead to the more efficient utilization of the transmission system. Essentially, Joint Protestors argue that because no new transmission capacity is being added to the overall transmission system to accommodate Net Zero projects, competing interconnection projects will be faced with higher pricing pressure at the node in the form of congestion charges or curtailments that they would otherwise not see.[346] As a result of this increased pricing pressure it will become more difficult for new renewable energy projects to become financeable.

268. Joint Protestors argue that Net Zero Interconnection Service violates the Public Utility Regulatory Policies Act (PURPA). They argue that if Net Zero Interconnection Service becomes an option under MISO's GIP, section 292.306 of the Commission's regulations prohibits MISO and any transmission owner within MISO from charging any Qualifying Facility (QF) that seeks interconnection any costs in excess of what it would be charged if it were a net zero interconnection. Likewise, they argue that the same rule

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[344] EcoEnergy Protest at 5-7.

[345] Joint Protestors Protest at 22.

[346] *Id.* at 36.

should equally apply to QFs with respect to special protection schemes, which have been used for net zero interconnections.[347]

269. Finally, Joint Protestors suggest that the Commission should exercise its authority under section 380.4(B) of its regulations to order an environmental assessment of Net Zero Interconnection Service. While the Joint Protestors acknowledge that section 380.4 categorically exempts actions under sections 205 and 206 of the FPA, they argue that the Commission should exercise its discretion to require an assessment where the environmental effects are uncertain. They claim that Net Zero Interconnection Service will result in less transmission being built and less renewable energy being developed.[348]

270. While generally supporting Net Zero Interconnection Service, Iberdrola states that the Commission should direct MISO to remove the requirement that the interconnection customer provide an executed Energy Displacement Agreement with its interconnection application and require a Memorandum of Understanding instead, as it believes the latter is sufficient to establish agreement between the existing generator and the interconnection customer.[349] Additionally, several parties propose revisions to different provisions of MISO's tariff concerning Net Zero, which they claim are necessary to ensure consistency throughout MISO's tariff and to clarify certain aspects of Net Zero Interconnection Service.[350]

c. <u>Answers</u>

271. In response to the protests, MISO states that existing generators seeking to take advantage of Net Zero Interconnection Service must retain business discretion in choosing which interconnection customers to pair with at a shared Point of Interconnection. MISO states that forcing an existing generator to pair with another interconnection customer based on queue order could result in the existing generator having to contribute to the cost of more expensive assets than another interconnection customer plans to use.[351]

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[347] *Id.* at 38.

[348] *Id.* at 39.

[349] Iberdrola Protest at 19.

[350] E.ON Protest at 7-8; MISO Transmission Owners Comments at 5-9.

[351] MISO December 15 Answer at 14.

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272. MISO Transmission Owners state that Net Zero Interconnection Service applies in the same manner to all new interconnection customers that wish to interconnect generation at the same location as an existing generator. Additionally, MISO Transmission Owners state that Transmission Owners have no more ability than any other generation owner to use Net Zero Interconnection Service to favor one generator over another because it is MISO that implements and administers the interconnection queue and the associated study processes.[352]

273. Xcel states that a Net Zero Interconnection Service generator will connect additional generation capacity at an existing Point of Interconnection without increasing the net output at that Point of Interconnection beyond levels that have already been studied. Net Zero Interconnection Service will allow a new generator to utilize existing transmission capacity when that existing capacity is not being utilized by the existing generator.[353] Thus, Net Zero Interconnection Service increases efficiency by enhancing competition among resources and by reducing the number of hours that existing system capacity is being underutilized.

274. Additionally, Xcel reiterates that the language in proposed Section 3.3.1 of the GIP requires the new generator to enter into an Energy Displacement Agreement with the existing generator to ensure that both generators have contractually agreed to the terms and conditions of the use of the interconnection capacity so that the net injections of energy do not exceed the existing interconnection capacity.[354]

275. Contrary to the protest of Joint Protestors, Xcel argues that Net Zero Interconnection Service allows generators that otherwise meet the criteria of the MISO Tariff to achieve commercial operation more quickly, thus expanding – not reducing – the opportunities for renewable generation in the MISO market. Also, Xcel states that it is MISO's transmission planning process that is intended to identify and require construction of transmission upgrades that will reduce congestion in order to provide transmission service.[355] That is, network upgrades for interconnection service do not relieve transmission system congestion as suggested by EPSA and Joint Protestors.

276. In response to EcoEnergy's comments that MISO's Tariff does not allow for Net Zero Interconnection Service, Xcel answers that several provisions within MISO's

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[352] MISO Transmission Owners Answer at 5-6.

[353] Xcel Answer at 4-5.

[354] *Id.* at 5-6.

[355] *Id.* at 6-7.

pro forma GIA are broad enough to allow for the safe and reliable interconnection of a generator under the Net Zero construct. For example, Sections 9.3 and 9.4 of the *pro forma* GIA obligate all parties to operate in a safe and reliable manner consistent with operating protocols and operating limits. Xcel posits that from an interconnection perspective, it is the net impact of the proposed interconnection on the transmission system, not the precise size or configuration of the generator itself, that matters. So long as measures are taken to ensure that the net output does not exceed the interconnection capacity, the system itself is indifferent.[356]

277. Regarding arguments that Net Zero Interconnection Service is unduly discriminatory, Xcel reiterates that the proposal does not limit who can request Net Zero Interconnection Service. That is, it is available to all new generators, non-utility and utility-owned alike. It is also available to all existing generators, including those of incumbent utilities and independent power producers. Additionally, the provisions do not impose any different non-operational requirements on any generator seeking to utilize Net Zero than would be required of a generator seeking to interconnect to the transmission system on its own.[357]

278. Xcel also states that Net Zero Interconnection Service does not facilitate queue jumping as alleged by Joint Protestors. Xcel explains that a Net Zero generator will affect the transmission system differently than other generators proposing to interconnect at the same point. Therefore, it is not unreasonable that the two types of projects progress through the interconnection process at different speeds based on their different system impacts.[358]

279. Rebutting Joint Protestors' assertions that an existing generator only has interconnection rights under the exact conditions it was studied and that the way in which it was modeled dictates the terms of the existing generator's interconnection rights, Xcel asserts that interconnection service is indisputably an around-the-clock product, meaning that generation is authorized to operate during all hours, whether or not a particular generator has been economically dispatched during any particular hour.[359]

280. Prairie Rose argues that Joint Protestors misstate the applicable standard and that MISO must show that its proposal meets the "independent entity" standard and not the

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[356] *Id.* at 9.

[357] *Id.* at 10.

[358] *Id.* at 13.

[359] *Id.* at 14.

"consistent with or superior to" standard. Prairie Rose maintains that MISO's proposed revisions to clarify Net Zero Interconnection Service under the tariff are just and reasonable because they will provide all parties with a uniform approach to the process of obtaining service. Prairie Rose argues that net zero interconnection should not be expected to provide every answer to the region's transmission capacity deficit and that significant new transmission will still need to be built over time. Nevertheless, Prairie Rose maintains that net zero interconnections are a significant step towards a more efficient utilization of the existing transmission grid.[360] Additionally, Prairie Rose argues that the Joint Protestors' claims of discrimination are without merit because the difference between their projects and the projects of those that will be able to take advantage of Net Zero Interconnection Service is factual in nature. In particular, Prairie Rose states that simply because Joint Protestors are not similarly situated to all other interconnection customers does not mean that MISO's proposed revisions equate to undue discrimination.[361]

d. Supplemental Filing

281. In response to questions posed in the December 30, 2011 deficiency letter, MISO states that it does not anticipate creating either a *pro forma* Energy Displacement Agreement or a *pro forma* Consent and Monitoring Agreement at this time but that it would consider doing so if such agreements become more widely used. However, MISO explains that at a minimum, any Energy Displacement Agreement would have to memorialize (1) that the term of the agreement is the same as the term of the GIA for the host generator; (2) that the existing generator will remain in commercial operation over that term; and (3) that the existing generator and the new generator are electrically located at the same Point of Interconnection. MISO explains that as a condition of service, the total combined output of both generators is limited to that of the existing generator (both real and reactive power) at the Point of Interconnection. As part of these conditions of service, MISO states that either the existing generator, the new generator, or the agent for both generators is solely responsible to maintain the coordinated output level within the proper rating and that if the new generator fails to perform as required, it will be curtailed to zero (0) MW until an operating plan is implemented by the two generators, the Transmission Owner, and MISO.[362]

282. MISO states that, as a condition of service, the Monitoring and Consent Agreement will require an annual self-certification by the net zero generator, that the

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[360] Prairie Rose December 15 Answer at 3-4.

[361] *Id.* at 5.

[362] Supplemental Filing at 17.

Energy Displacement Agreement and the Monitoring and Consent Agreement are both in place and that no party is in breach or default of either agreement.[363]

283. Regarding what information would be included in the appendices to a net zero GIA in order for MISO to ensure that the customer is operating under the appropriate output and under appropriate conditions, MISO states that a net zero facility is required to meet Attachment X Appendix I requirements that a net zero generator, in coordination with the existing generator, is required to maintain a total combined output limit within the rating of the existing generator at the Point of Interconnection.[364]

284. In describing the process of obtaining net zero service, MISO states that it anticipates two ways an interconnection customer could identify an opportunity for a net zero interconnection. First, the interconnection customer can examine the vicinity of its proposed location and seek out, if one exists, an existing generator to work out an arrangement. Second, an owner of an existing unit could advertise that it is willing to partner with a prospective interconnection customer. In either case, it would be incumbent on the interconnection customer to develop the opportunity.[365]

285. Regarding the costs involved with consummating a net zero arrangement, MISO states that from a tariff perspective the existing customer is not subject to any additional upgrade costs. However, MISO states that it would consider an existing generator deciding to fund some of the required connection equipment to facilitate the net zero interconnection as a bilateral agreement between the two interconnection customers. Similarly, any compensation by the new generator to the existing generator would also be agreed to through a bilateral arrangement.

286. In response to a question regarding the studies performed for an existing natural gas peaking plant and the studies performed for a generator seeking Net Zero Interconnection Service, MISO explains that regardless of the fact whether an existing peaker plant was studied under off-peak conditions or not, MISO's Business Practices Manual requires MISO to perform reliability analysis for a new interconnection under summer peak load conditions and shoulder load conditions. Further, MISO states that whether an existing generator was studied "off peak," MISO states that it depends on the rules that were in place at the time the generator was studied and that there will not be a hard and fast rule because some projects were studied under MAPP rules. Finally, MISO explains that it will ensure that a net zero customer only receives Energy Resource

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[363] *Id.* at 17-18.

[364] *Id.* at 18.

[365] *Id.* at 18-19.

Interconnection Service by indicating in its interconnection database the new generator is a net zero generator and therefore only allowed Energy Resource Interconnection Service. Additionally, MISO states that when it is preparing the draft GIA for the customer, the parties to the GIA would select Energy Resource Interconnection Service rather than Network Resource Interconnection Service in section 4.1 of the GIA.[366]

e. Comments on Supplemental Filing

287. Joint Protestors allege that two recent developments demonstrate that Net Zero Interconnection Service grants privileged access to existing capacity and potentially requires the redispatch of existing customers to address resulting overloads. First, the Joint Protestors allege that a review of the Definitive Planning Phase Cycle1 Re-Restudy by Power System Engineering, Inc. shows that MISO has changed its study assumptions in order to lock-in the perceived net zero rights of incumbent utilities and lay the groundwork for a massive implementation of Net Zero Interconnection Service.[367]

288. Second, the Joint Protestors allege that MISO is planning to displace existing projects with the Prairie Rose project, which demonstrates that MISO's proposal allows projects that receive Net Zero Interconnection Service to displace other projects. In this regard, they note that the updated quarterly curtailment spreadsheet for the fourth quarter of this year indicates that existing projects are being curtailed to accommodate the interconnection of Prairie Rose.[368]

289. The Joint Protestors state that while MISO has provided an "Energy Needs" graph showing the projects in the queue and the projected renewable energy needs of its members, MISO should be required to produce an analysis that shows how much wind generation would be eligible for net zero interconnection, as such an analysis would shed some light on the Joint Protestors assertions that net zero will allow the existing incumbent utilities to essentially control access for the foreseeable future. The Joint Protestors note that MISO's "Energy Needs" graph indicates that 5,000 MW of additional wind will be needed to meet RPS standards in 2020 and that the nameplate capacity for gas peaker plants within MISO appears to be 24,646 MW, which would allow for Net Zero projects that are a multiple of that difference. They maintain that these peaking-plants coupled with net zero interconnections would allow incumbent generators to corner the market for decades. The Joint Protestors also argue that there will be little incentive to build transmission in furtherance of the policy of Order No. 1000 because

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[366] *Id.* at 19-20.

[367] Joint Protestors February 21 Protest at 7.

[368] *Id.* at 8-11.

Net Zero Interconnection Service could be used to cover all foreseeable renewable energy mandates of the MISO utilities.[369]

290. With respect to MISO's assertion that it is required to perform reliability analyses under summer peak load conditions and shoulder load conditions for all new generator interconnections, the Joint Protestors argue that net zero projects are not being studied properly. They maintain that MISO's assertion is intended to create the impression that complete studies are being done for net zero interconnection, which is not the case and is demonstrated by the lack of network upgrades necessary to provide service to Prairie Rose and the millions of dollars of upgrades proposed for projects at the same point of interconnection.[370]

291. The Joint Protestors contend that, at its core, Net Zero Interconnection Service is unfair. In particular, they note that this construct has allowed Prairie Rose's project to cut in front of their projects and, as a result, has rendered their years of effort and investment worthless.[371] Moreover, the Joint Protestors state that MISO failed to employ an open stakeholder process in developing its net zero proposal and that such notification is the minimum constitutional requirement that would need to be observed.[372] For these reasons, the Joint Protestors request that the Commission reject MISO's proposed tariff changes in their entirety or suspend them for the full statutory period and set them for evidentiary hearing.

292. E.ON states that there are three specific problems with MISO's responses regarding Net Zero Interconnection Service. First, E.ON avers that MISO has not explained why the net zero generator must be curtailed to zero (0) MW when the violation of coordinated output limits is due to the actions of the existing generating customer and not the net zero generator. Second, MISO has not explained how long any curtailment will be imposed and the basis for that duration. Finally, MISO must explain the basis for allowing a Transmission Owner to initiate curtailment rather than MISO as the Transmission Provider.[373]

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[369] *Id.* at 11-12.

[370] *Id.* at 12.

[371] *Id.* at 13-14.

[372] *Id.* at 18-19.

[373] E.ON February 21 Protest at 7.

f. Commission Determination

293. We accept MISO's proposal to implement Net Zero Interconnection Service on the condition that it modify its proposal as further discussed below.[374]

294. We agree with MISO and commenters that Net Zero Interconnection Service will promote the more efficient utilization of existing interconnection capacity. In this regard, we find that MISO's proposal is consistent with prior Commission precedent. For instance, the Commission has permitted the voluntary reassignment of all or part of a holder's firm point-to-point capacity rights to any eligible customer because it believed that such reassignment will foster efficient capacity allocation.[375] The Commission previously accepted MISO's proposal to permit the provision of conditional Energy Resource Interconnection Service and Network Resource Interconnection Service because the proposal provided benefits by making use of available capacity and promoting the more efficient use of the transmission system.[376] We believe that Net Zero Interconnection Service will provide similar benefits by allowing an interconnection customer receiving this service to use interconnection capacity at an existing point of interconnection when that capacity is not being fully utilized by an existing generator. In this regard, we believe that Net Zero Interconnection Service will promote one of the goals of Order No. 2003; it will "increase energy supply and lower wholesale prices for customers by increasing the number and variety of new generation that will compete in the wholesale electricity market."[377]

295. We disagree with those protesters that argue that Net Zero Interconnection Service does not make more efficient use of the transmission system. These protestors argue that

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[374] MISO and several protesters have raised the issue of whether MISO's tariff currently permits the provision of Net Zero Interconnection Service. This issue is addressed in an order that is being issued concurrently with this order. *Shetek Wind Inc., Jeffers South, LLC and Allco Renewable Energy Limited v. The Midwest Independent System Operator, Inc.,* 138 FERC ¶ 61,250 (2012).

[375] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,696 (1996).

[376] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 61,306, at PP 3-4 (2006).

[377] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 1.

the transmission system is already being fully used and that Net Zero Interconnection Service will increase congestion costs and curtailment. Although we acknowledge that Net Zero Interconnection Service will not obviate the need to further expand the transmission grid, we believe that allowing a new generator to use interconnection capacity when an existing generator is not using that capacity allows for more efficient use of interconnection capacity.

296. Additionally, we disagree with the assertion that we should require an environmental assessment of Net Zero Interconnection Service. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[378] However, as Joint Protestors acknowledge, section 380.4(a)(15) of the Commission's regulations provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[379] Section 380.4 does provide for an exception to this exclusion where circumstances indicate that the proposal may be a major federal action significantly affecting the quality of the human environment, including situations where the environmental effects are uncertain.[380] In this case, however, there is no evidence in the record of identifiable environmental harm that would likely result from the implementation of Net Zero Interconnection Service. Accordingly, we will decline to require the preparation of an Environmental Assessment or an Environmental Impact Statement.

297. We also disagree with the argument that Net Zero Interconnection Service violates PURPA. In support of their argument, Joint Protestors cite section 292.306(a) of the Commission's regulations. This section, however, only applies to non-jurisdictional interconnections. The interconnection of a QF is jurisdictional where the QF is permitted to make sales to a third-party purchaser (i.e., a party other than the directly interconnected utility).[381] Any QFs that were to take service under MISO's Tariff would be transmitting power in interstate commerce and, therefore, this rule is inapplicable here.

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[378] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[379] 18 C.F.R. § 380.4(a)(15) (2011).

[380] 18 C.F.R. § 380.4(b).

[381] *Western Massachusetts Electric Co.*, 61 FERC ¶ 61,182, at 61,662 (1992), *aff'd sub nom.* 165 F.3d 922, 926 (D.C. Cir. 1999); *see also Midwest Indep. Transmission Sys.*

(continued…)

298. While we recognize the benefits of Net Zero Interconnection Service, we also share some of the concerns raised by the protesters regarding studies for resources during off-peak conditions. For instance, we are concerned that a net zero resource would be able to share interconnection rights with an existing generator that was not evaluated under the conditions that the net zero resource would utilize. This is a concern because resources such as wind typically operate in off-peak hours and if they wish to interconnect using Net Zero Interconnection Service, they could potentially interconnect to a resource such as a peaker unit that may not have had an off-peak study performed for its interconnection capacity. In the Supplemental Filing, MISO states that its Business Practices Manual requires it to perform reliability analysis for a new interconnection under summer peak load conditions and shoulder load conditions.[382] Therefore, we require MISO to include in its compliance filing tariff language that details how it will address net zero projects that wish to interconnect to existing generators that were not studied under off-peak conditions.

299. Additionally, we also share concerns with protesters on potential competitive implications of the manner in which MISO proposes to implement this service. In particular, we are concerned that MISO's proposal creates opportunities for undue discrimination and preferential treatment. Under MISO's proposal, prior to submitting a request for Net Zero Interconnection Service to MISO, the interconnection customer must have entered into a memorandum of understanding with the relevant Transmission Owner to enter into a Monitoring and Consent Agreement upon execution of a GIA and, if the interconnection customer seeking Net Zero Interconnection Service is not the owner or a subsidiary of the owner of the existing generating facility at the point of interconnection, enter into an Energy Displacement Agreement with the owner of the existing generator.[383] Thus, in effect, MISO's proposal provide an existing generator and Transmission Owner the ability to grant access to this service to some customers and not to others.

300. MISO argues that an existing generator must have business discretion to choose which interconnection customer to pair with at a shared point of interconnection.[384] Regardless of whether an existing generator should be compelled to permit the provision

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Operator, Inc., 132 FERC ¶ 61,241 (2010); *see also Florida Power & Light Co.*, 133 FERC ¶ 61,121 (2010).

[382] Supplemental Filing at 19.

[383] *See* proposed revised section 3.3.1; *See also* Supplemental Filing at 18-19.

[384] MISO December 15 Answer at 13-14.

of Net Zero Interconnection Service at an existing point of interconnection, once an existing generator decides to do so, that service must be provided in a manner that is just and reasonable and not unduly discriminatory or preferential. The manner in which MISO proposes to implement Net Zero Interconnection Service does not meet this standard.

301. Moreover, we are concerned by the lack of transparency in MISO's proposal. As an initial matter, MISO's proposal does not provide a clear and consistent way in which generators seeking Net Zero Interconnection Service may identify opportunities for Net Zero Interconnection Service or how such a generator would be chosen for such service.[385] Additionally, MISO proposes to leave many of the rates, terms, and conditions of obtaining Net Zero Interconnection Service to the agreement of the parties and does not propose to require the filing of these agreements with the Commission. For example, MISO takes the view that any compensation that an existing generator receives from the provision of Net Zero Interconnection Service should simply be left to the parties and does not propose to require disclosure of the compensation paid for this service. Further, based on the information provided, it appears that MISO does not expect Energy Displacement Agreements and Monitoring and Consent Agreements to be filed with the Commission. MISO's position, however, overlooks the fact that the Commission has identified interconnection as an element of transmission service and, as a result, rates, terms and conditions of such service must be filed with the Commission under section 205 of the FPA.[386]

302. Given these concerns, we direct MISO to submit a compliance filing, within 180 days of the date of this order, revising its Tariff to implement additional procedures that ensure that Net Zero Interconnection Service is offered on a fair, transparent, and non-discriminatory basis and that comply with the filing requirements of FPA section 205. We will leave it to MISO to develop an approach that is workable from its perspective and ensures that non-discriminatory open access principles are preserved; however, we expect that the revisions proposed in MISO's compliance filing will be informed by prior Commission efforts to promote open access and eliminate undue discrimination in other contexts. For instance, in the context of interconnection service, the Commission has required Transmission Providers to file *pro forma* interconnection documents. In Order No. 2003, the Commission required the use of *pro forma* documents in order to ensure that interconnection customers receive non-discriminatory service and that all interconnection customers are treated on a fair and consistent basis.[387] The Commission

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[385] Supplemental Filing at 18-19.

[386] Order No. 2003, FERC Stats. & Regs. ¶ 31,146; 16 U.S.C. § 824d.

[387] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 12.

also rejected arguments by some commenters that there was no need to require independent Transmission Providers to be signatories to the interconnection agreement because the responsibilities of the Transmission Provider can be fully addressed in the tariff and the main purpose of the agreement was to establish a property-based relationship between the interconnection customer and the Transmission Owner. The Commission found that requiring the Transmission Provider to be a party to the interconnection agreement would better define the relationship among the parties, protect the interconnection customer, and facilitate the development of new generation resources.[388]

303. Additionally, while the Commission has permitted the reassignment of firm point-to-point capacity rights, the Commission has imposed certain posting and reporting requirements in order to increase transparency, to facilitate the monitoring of the secondary market for transmission capacity, and to ensure that rates for reassigned transmission capacity remain just and reasonable and are not unduly discriminatory or preferential. First, the Commission has required that all sales or assignment of capacity be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences. Second, the Commission has required that assignees of transmission capacity execute a service agreement with the Transmission Provider prior to the date on which the reassignment of service commences. Third, the Commission has required Transmission Providers to aggregate and summarize the data contained in these service agreements and report this data in an electric quarterly report.[389]

304. Similarly, the Commission has imposed requirements to enhance transparency and protect against undue discrimination in the release of firm capacity by shippers on interstate natural gas pipelines. In Order No. 636, the Commission required gas pipelines to unbundle their transportation and storage services from their sales service, so that gas purchasers could obtain high quality firm transportation service whether they purchased from the pipeline or another gas seller. In order to create a transparent program for the reallocation of interstate pipeline capacity, the Commission adopted a comprehensive capacity release program by permitting firm shippers to release their capacity to others when they were not using it. In order to ensure that firm shippers could not reallocate their capacity in a discriminatory manner, the Commission placed several conditions on

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[388] *Id.* PP 908-909.

[389] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at PP 815-818, *order on reh'g*, Order No. 890-A, 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 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

the transfer of capacity: (1) the Commission prohibited private transfers between shippers and required that all release transactions be conducted through the pipeline; (2) the Commission imposed a ceiling on the rate the releasing shipper could charge for the released capacity; (3) the Commission required that the capacity offered for release at less than the maximum rate must be posted for bidding and allocated to the entity offering the highest rate; and (4) the Commission prohibited tying the release of capacity to any extraneous conditions so that the releasing shippers could not attempt to add additional terms or conditions to the release of capacity.[390]

305. In the market-based rate context, the Commission has enacted regulations to protect against concerns regarding the potential for affiliate abuse and has stated that, in cases where affiliates are entering into market-based rate sales agreements, it is essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted.[391] Under *Edgar*, the Commission has approved affiliate sales resulting from competitive bidding processes after the Commission has determined that, based on the evidence, the proposed sale was not the result of affiliate preference and was instead the result of direct head-to-head competition between affiliated and competing unaffiliated suppliers.

306. In sum, while we find that MISO's proposal to permit the sharing of interconnection capacity will promote the efficient use of the transmission system, we have serious concerns about the manner in which MISO proposes to implement this service and find that MISO's proposal requires modification in order to meet the Commission's standards respecting transparency and to eliminate the potential for undue discrimination. We expect that, on compliance, MISO will propose a MISO-administered

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[390] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs. ¶ 30,939, *order on reh'g*, Order No. 636-A, FERC Stats. & Regs. ¶ 30,950, *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *order on reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom. United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997). The Commission modified these requirements in subsequent orders to accommodate market changes. *See, e.g., Promotion of a More Efficient Capacity Release Market, Order* No. 712, FERC Stats. & Regs. ¶ 31,271, at PP 24-29 (2008), *order on reh'g*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh'g*, Order No. 712-B, 127 FERC ¶ 61,051 (2009).

[391] *Boston Edison Co. Re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382, at 62,167-69 (1991) (*Edgar*).

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process that ensures that Net Zero Interconnection Service is offered in a manner that is consistent with section 205 of the FPA, generators operate in a manner that respects the rights of all market participants, and service is available on a fair, transparent and non-discriminatory basis.

The Commission orders:

(A) MISO's tariff sheets are hereby conditionally accepted, effective January 1, 2012, as discussed in the body of this order.

(B) MISO is hereby directed to make a compliance filing within 30 days of the date of issuance of this order modifying its proposed tariff revisions as discussed in the body of order, other than the section discussing Net Zero Interconnection Service.

(C) MISO is hereby directed to make a compliance filing within 180 days of the date of issuance of this order modifying its proposed tariff revisions as discussed in the body of the section of this order addressing Net Zero Interconnection Service.

(D) MISO is directed to file in April 2013, April 2014, and April 2015, informational reports detailing the effectiveness of the reforms approved in this order and on compliance.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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Appendix A

The listed parties have filed motions to intervene in Docket No. ER12-309-000. A short-name reference to a party, shown in parentheses after the full name, indicates that the party also filed comments or a protest or is otherwise mentioned in the order.

Akuo Energy USA Inc. (Akuo)
Alliant Energy Corporate Services, Inc. (Alliant)
American Municipal Power, Inc. (AMP)
American Wind Energy Association and Wind on the Wires (AWEA and WOW)

Calpine Corporation (Calpine)
Clipper Windpower Development Co., LLC (Clipper)
Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc.
Consumers Energy Company
CPV Renewable Energy Company, LLC

Detroit Edison Company (Detroit Edison)
Duke Energy Corporation

EcoEnergy LLC (EcoEnergy)
Edison Mission Energy (Edison)
EDP Renewables North America LLC (EDP)
Electric Power Supply Association (EPSA)
Element Power US, LLC (Element)
E.ON Climate & Renewables North America LLC (E.ON)
Exelon Corporation

Flat Hill Windpark I, LLC (Flat Hill)

Gamesa Energy USA, LLC
Geronimo Wind Energy (Geronimo)

Iberdrola Renewables, Inc. (Iberdrola)
Integrys Energy Group, Inc.
Invenergy Wind Development LLC and Invenergy Thermal Development, LLC (Invenergy Companies)

Juhl Wind, Inc. (Juhl)

LS Power GenCo, LLC

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Midwest Developers [1]
Midwest TDUs [2]
MISO Transmission Owners [3]

National Renewable Solutions, LLC (National Renewable Solutions)
NextEra Energy Resources, LLC (NextEra)

PNE WIND USA, Inc.
Prairie Rose Wind, LLC (Prairie Rose)
Project Resources Corporation
Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC

Renewable Energy Systems Americas, Inc.

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[1] The Midwest Developers are the Invenergy Companies, Clipper, Edison, E.ON, PNE Wind USA, Inc., St. Joseph Energy Center, LLC, and Element. It should be noted, however, that E.ON was not a party to the answer.

[2] Midwest TDUs consists of Madison Gas and Electric Company, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy System, and WPPI Energy.

[3] The MISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Michigan Electric Transmission Company, LLC; Michigan Public Power Agency; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; 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 Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

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Shetek Wind, Inc., Jeffers South LLC, and Allco Renewable Energy Limited (Joint Protestors)
St. Joseph Energy Center, LLC

Wisconsin Electric Power Company
Wisconsin Public Service Corporation

Xcel Energy Services, Inc. (Xcel)