EVALUATION OF MVP TRANSMISSION COST ALLOCATION DESIGN

Prepared by Scott Harvey and Susan Pope

June 9, 2010

TABLE OF CONTENTS

EVALUATION OF MIDWEST ISO MVP TRANSMISSION COST ALLOCATION DESIGN[1]

Prepared by Scott Harvey and Susan Pope[2]

I. Introduction

This paper provides a qualitative assessment of the market impacts of the Multi-Value Project ("MVP") methodology that the Midwest ISO is currently discussing as a means to allocate and recover in transmission charges the costs of several categories of future transmission investments ("the MVP methodology"). Our objective is to identify those market impacts that are most likely to be material. We also have provided an explanation of factors that are likely to amplify or lessen the potentially adverse market impacts of the MVP methodology.

Section II provides a brief summary of the equity principles that underlie the design of the MVP methodology, a background discussion of how transmission expansions typically impact locational prices in competitive power markets, and a conceptual explanation of how the design of the charges used to recover the cost of transmission investments can impact the realization of the benefits from those investments.

---

1 This revised report contains addresses the MVP cost allocation proposal described in Midwest ISO, "Transmission Cost Allocation Design, Midwest ISO MVP Cost Allocation Proposal," June 3, 2010 (hereafter "June 3, 2010 Proposal").

2 Scott Harvey is a director and Susan Pope a principal with LECG, LLC. They are and have been consultants to the Midwest ISO on a variety of other issues. The authors have also been consultants on issues relating to electricity market design and performance, transmission rights and pricing, and market power for a variety of other organizations and market participants in the electric power industry as listed in Addendum A. The discussion of Midwest ISO Guiding Principles in Section IIA is based on material provided by Jennifer Curran of the Midwest ISO, and the description of the MVP methodology in Section III benefited from detailed comments by Jesse Moser of the Midwest ISO. Jennifer Curran and Dhiman Chatterjee, also of the Midwest ISO, provided helpful comments on this and earlier versions of the report. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are the responsibility of the authors.

Section III provides a fairly complete conceptual level explanation of the MVP methodology, both those elements that are relatively well defined, and a few that are still evolving.

Section IV contains our evaluation of potential market impacts of the MVP methodology. Section V contains our recommendations, and a brief discussion of why we have not recommended changes in some elements of the design to address impacts that are discussed in Section IV.

II. Cost Allocation and the Benefits of Transmission Expansion

A. Midwest ISO Guiding Principles

The goal of the Midwest ISO cost allocation discussion is to develop a fair cost allocation mechanism that enables transmission development to support reliability and economic goals, renewable integration, and public policy while maintaining the Midwest ISO Value Proposition. Based on feedback from stakeholders and experience with the existing method for allocating transmission costs, the Midwest ISO developed four principles to focus and guide the development of an injection/withdrawal cost allocation methodology to align with this goal. These four principles are:

- *Eliminate / Minimize Free Riders*: The transmission cost allocation methodology should allocate the costs of lumpy transmission upgrades to all present and future beneficiaries from those upgrades.
- *Ensure the "Right" Loads Pay:* The cost of transmission upgrades should be borne by the loads benefiting from those investments even if they are remote from the transmission investment and/or affected generation.
- *Reflect Changing System Usage Over Time*: The cost allocation should be able to change over time to reflect changes over time in those who benefit from the investments.
- *Balance Attributes of System Use*: The cost allocation should strike a balance among alternative methods for assigning costs:

– The direct causer of a transmission project vs. all beneficiaries.
– Local vs. regional beneficiaries of the transmission project.
– Transmission to meet reliability needs vs. to reduce the cost of energy or to meet environmental goals.

Eliminate/Minimize Free Riders

Under many methodologies presently or formerly in use for allocating transmission costs, future transmission users may benefit from the use of transmission upgrades without having to share in the cost of those upgrades. The free rider issue often arises in the context of network upgrades built for the interconnection of new generation. Transmission upgrades are generally "lumpy", meaning that the transmission capacity enabled by the initial generator's network upgrades will allow additional generators in the area to interconnect without the need to fund additional network upgrades. If this occurs, the later generators are said to be "free-riding" on the initial generator's investment because they are benefiting without sharing in the cost of the transmission upgrades funded by the initial interconnecting generator. Similarly, existing generators or loads may benefit from their ability to utilize the enhanced system transfer capability provided by a new transmission upgrade.

The Midwest ISO is seeking to develop a cost allocation methodology that will allocate the costs of lumpy transmission upgrades to all present and future beneficiaries from those upgrades. The new cost sharing methodology should seek to minimize the ability of users to benefit from new transmission without incurring an appropriate share of the cost.

Ensuring the "Right" Loads Pay

One unintended consequence of methodologies presently or formerly in use for allocating transmission costs is that a disproportionate share of transmission expansion costs could be allocated to load in certain parts of the RTO footprint. Historically, generation has been built close to load so that a cost allocation method that allocated transmission costs primarily to load in the zone where an interconnecting generator was located worked fairly well. However, with the advent of renewable portfolio standards, a large amount of wind generation seeks to locate in the western zones of the Midwest RTO, even though load in the western zones may not require the generation to meet either load growth or state renewable mandates. In addition, the association between generation and the load that benefits from the generation can change over time.

Thus, the Midwest ISO is seeking to develop a cost allocation methodology that will allocate transmission costs to those loads that benefit from new interconnecting generation and its accompanying transmission. To address the objective of ensuring that the "right" load pays, areas using the transmission system to either export or import additional energy should also pay a share of the costs of transmission commensurate with their use of the system.

Reflecting Changing System Usage Overtime

The use, purpose and function of a transmission facility often changes over time with the result that the beneficiaries of that project also change. Cost allocation methodologies that allocate transmission costs only once prior to a project going into service do not take into account that the beneficiaries of the project will change over time. The Midwest ISO is seeking to develop a cost allocation methodology that can change the allocation of transmission costs over time as appropriate to reflect changes in the beneficiaries over time.

Balance Attributes of System Use

Historical approaches to cost allocation have tended to focus on one or the other extreme of a range of attributes that could potentially be used as the basis for the allocation. The Midwest ISO is seeking to develop a cost allocation methodology that strikes a balance among alternative methods for assigning costs with the goal of decreasing the polarity between perceived "winners" and "losers."

Direct Cost Causer vs. All Beneficiaries

The direct causer of a transmission project, such as a generator requesting interconnection to the transmission system, or a Transmission Owner needing to meet a NERC reliability standard, is a beneficiary of that project but may not be the only beneficiary of the project. Because the cost causer is not necessarily the only beneficiary, allocating all of the transmission costs to only the direct cost causer can allow the other beneficiaries a "free ride." The Midwest ISO is seeking to develop a cost allocation methodology that strikes an improved balance in the allocation of costs between the direct cost causer and all beneficiaries.

Local Beneficiaries vs. Regional Beneficiaries

Over time the use of the transmission system has been shifting from a more localized system where local generation serves local load to a system where there are increased regional transfers driven by the economics of the energy market and state energy renewable mandates. Every transmission project will offer different levels of local versus regional benefits depending on the location of the project, load and generation in the area, the project size, etc. An important consideration in developing a fair cost allocation methodology is to find a way to measure the local versus regional use of the transmission system and charge local and regional users appropriately.

Access (Demand) Charge vs. Usage (Energy) Charge

Historically, transmission has been designed to meet reliability needs and transmission charges have, correspondingly, been made on the basis of demand. In the Midwest ISO, with its centrally dispatched market, portions of the system are increasingly used and designed to facilitate energy transfer across the footprint in addition to meeting the reliability needs of the system. The Midwest ISO is seeking to develop a cost allocation method that will recognize both of these attributes of transmission usage.

B. Market Impacts of Transmission Expansions

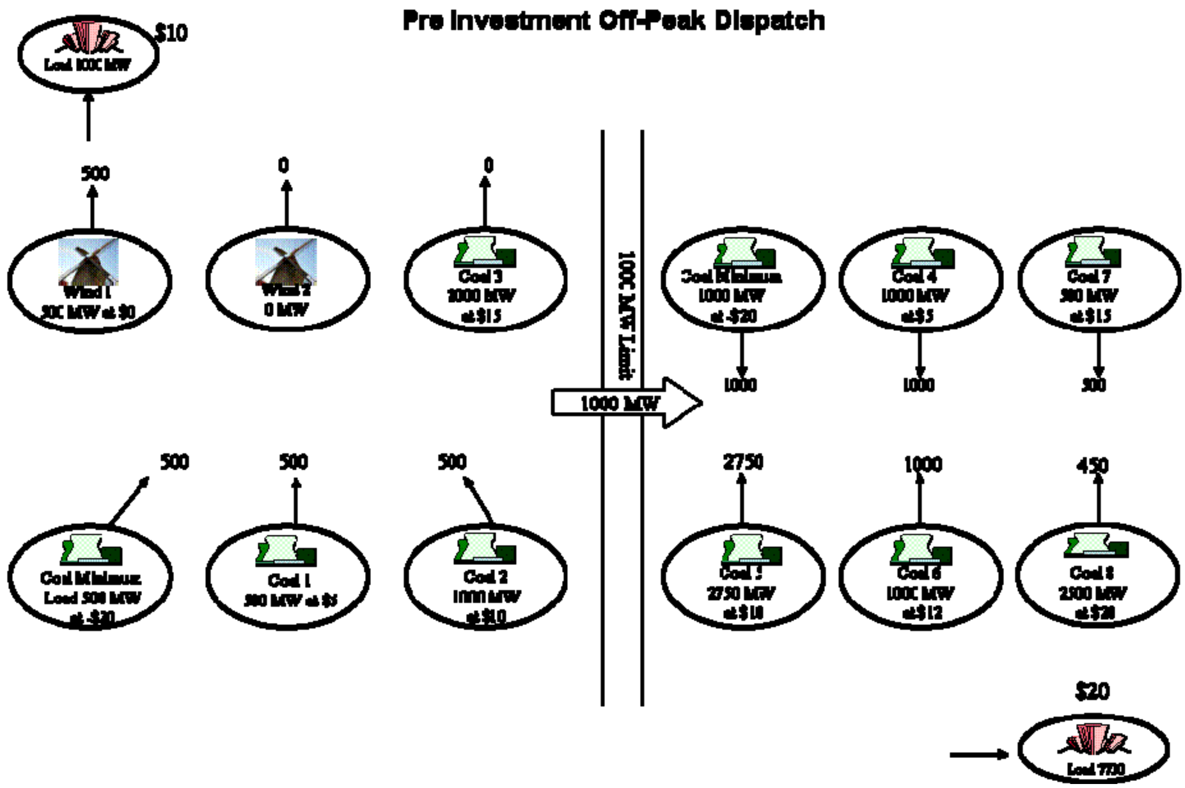
The discussion below of the potential market impacts of the injection/withdrawal methodology for recovering the costs of transmission expansion is premised on an understanding of the way in which transmission expansions impact market prices and congestion patterns. This section provides a brief review of these price and congestion impacts to provide a common understanding for the discussion that follows.

One generally expects that in the case of economically driven transmission investments that there would be material transmission congestion during at least some hours prior to the transmission investment. Thus, there would be low cost generation that could not be dispatched, requiring that load be met with higher cost generation located on the constrained side of the transmission system.

This situation is illustrated in Figure 1, in which generation with an offer price of $15 remains undispatched on the western side of a binding transmission constraint while higher cost generation (offered at $20 per megawatt hour) is dispatched to meet load on the eastern side of the transmission constraint.

Figure 1

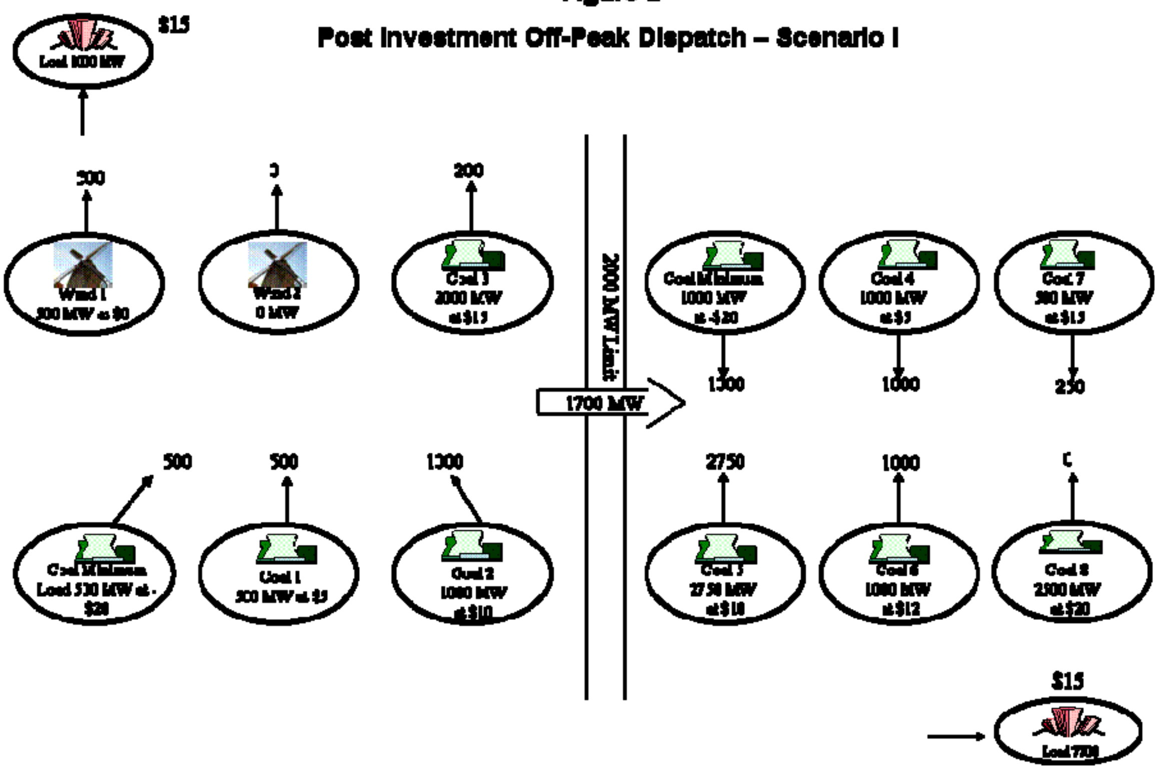
Pre Investment Off-Peak Dispatch



The immediate impact of an expansion to the transmission system between the constrained and unconstrained areas in such a situation will likely be to reduce or eliminate transmission congestion. This will likely cause locational prices to rise for both generators and loads in the region in which prices were previously depressed by congestion, and likely cause some decrease in locational prices in the region in which higher cost generation is no longer needed to meet load. This kind of change in locational prices from a transmission expansion is illustrated in Figure 2, where the price of power rises from $10 to $15 in the west, and falls from $20 to $15 in the east. In this example the total payments by load[3] fall after the transmission expansion, but one can also construct examples in which the overall payments by load[4] rise after the expansion.[5] The key impact is that the production cost of meeting load falls by $4,750 in the example portrayed in Figure 2.[6] This kind of change in which congestion is completely eliminated will be referred to as Scenario I in some of the discussion below.

Figure 2

Post Investment Off-Peak Dispatch – Scenario I



Importantly, the impact of the expansion of the transfer capability of the transmission system will likely not be limited to the short-run changes in the dispatch and locational prices illustrated in Figures 1 and 2. These changes in transfer capability will provide an incentive for additional generation investments that would have been uneconomic absent the transmission expansion. Thus, there might be opportunities for additional generation

---

3 Net of congestion rents

4 The megawatts of load times the locational price summed over all load in the market, minus the congestion rents.

5 The NYISO, for example, carried out a simulation evaluation using historical offer price and load data (allowing the unit commitment to change) of the impact of eliminating all transmission congestion internal to New York, and found that while the production cost of meeting load fell, net payments by load rose overall, rising more in the west than in the east.

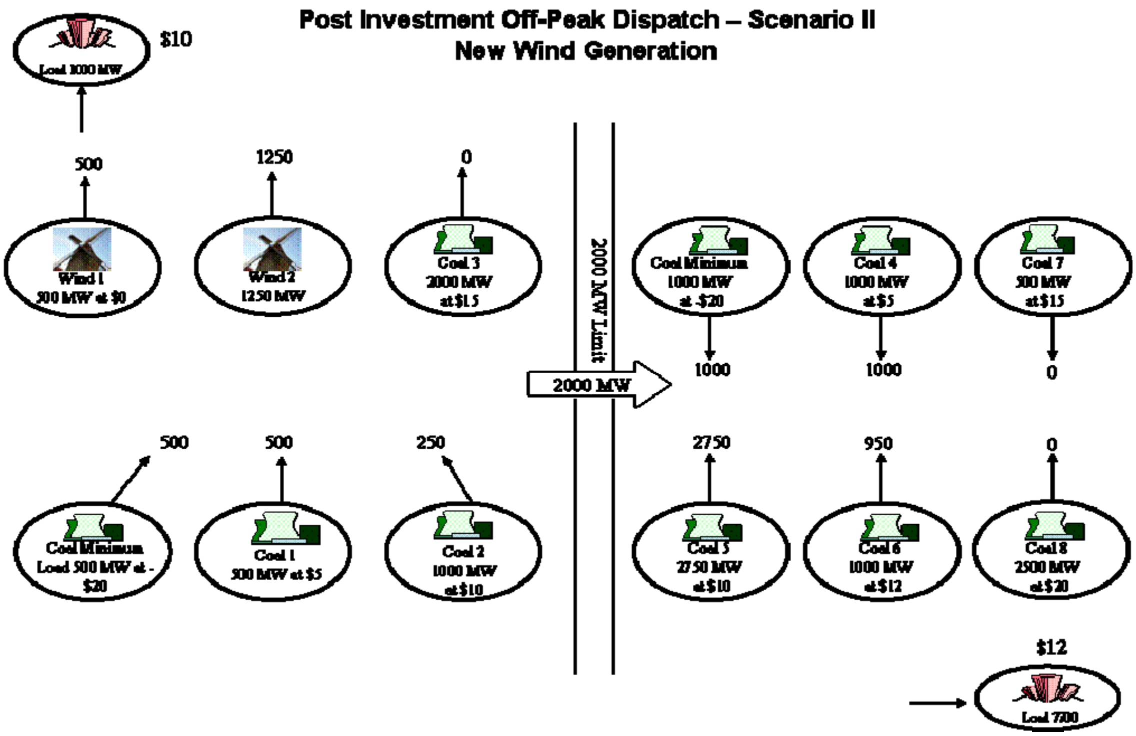
6 450 megawatts of generation at $20 and 50 megawatts at $15 are replaced by generation that costs $10.

investments in the west that were not made prior to the transmission expansion because they would have increased transmission congestion and driven prices in the west so low that the investments would not have been economic. With the transmission expansion, these generation investments would look more profitable. When these generation investments are made, they would tend to restore west to east transmission congestion and drive prices back down on the constrained down side of the transmission system, while leaving prices slightly lower on the constrained up side of the transmission system.

This kind of longer run outcome is illustrated in Figure 3 in which additional wind generation with a low offer price has been sited on the western side of the transmission system. As a result, the transmission system is again constrained from west to east in off-peak hours, but the production cost of meeting load has fallen by another $14,850.[7] This kind of outcome, in which additional generation is built until the transmission systems is again congested is referred to as Scenario II below.

Figure 3

Post Investment Off-Peak Dispatch – Scenario II
New Wind Generation

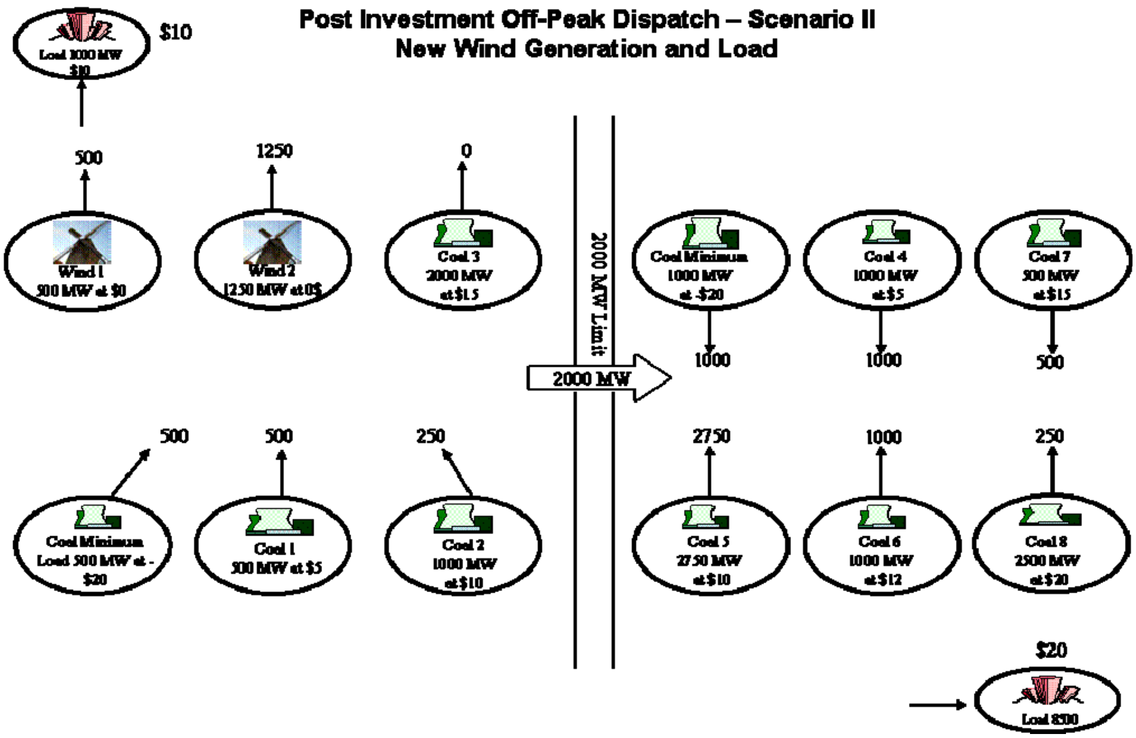


7 1,250 megawatts of wind generation have replaced coal generation costing $10 and $15.

Historically it has generally been the case that reductions in transmission congestion associated with transmission expansions are not permanent, because demand growth (and generation entry and exit) eventually restores the congestion pattern that existed prior to the expansion. This is illustrated in Figure 4 in which demand growth has restored congestion, and prices are the same as they were prior to the expansion.

Figure 4

Post Investment Off-Peak Dispatch – Scenario II
New Wind Generation and Load



Although the transmission system is again congested, the cost of meeting load in the example portrayed in Figure 4 has been reduced by the transmission expansion and the investment in wind generation relative to what it would otherwise have been after the growth in load, with most of the $22,500 reduction in the cost of meeting load reflected in increased congestion rents ($20,000 additional congestion rents associated with the incremental 1000 megawatts of transfer capability given that the LMP in the east is $20 and the LMP in the west is $10). These congestion rents, which are attributable to the additional transmission capacity from the west to the east, will accrue to parties who obtain the additional FTRs made feasible by the transmission expansion. Thus, in the longer-run, the value of the transmission expansion may be manifested less in changes in locational prices and more in congestion rents that accrue to the FTRs associated with the increased transfer capability.

The transmission investments whose costs will be recovered in the transmission charges of the injection/withdrawal methodology will have the potential to impact market prices as illustrated in this example, raising prices in some areas and reducing prices in other areas following the transmission investment, with congestion potentially returning over time as generation investments are made and load growth occurs. Whether generators and loads in particular areas will benefit from the price impacts of particular investments will depend in the short-run on their location relative to the congestion patterns addressed by the generation investments and in the longer run on how the FTRs made feasible by the transmission investments are allocated.

C. Market Impacts of Transmission Charges

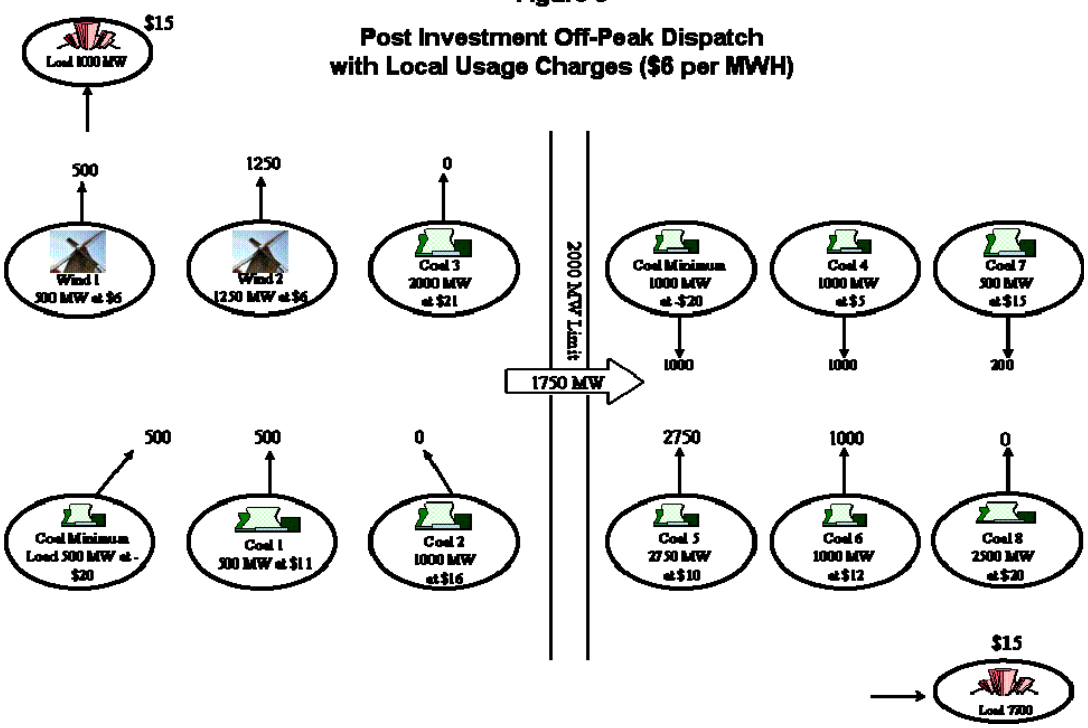
The principles listed in Section A above pertain to the balance of equities that are intended be achieved with the MVP methodology for allocating transmission costs. The focus of our analysis, however, is not on assessing the extent to which the MVP methodology will achieve those outcomes either quantitatively or qualitatively. Instead, the Midwest ISO has asked us to provide a qualitative assessment of the market impacts of the MVP transmission cost methodology.

The potential issue that motivates this assessment of market impacts is that how the costs associated with a given transmission investment are recovered can have market impacts that affect the magnitude of the benefits realized from those investments. As we briefly discuss below, the design of the MVP methodology will not perfectly match charges to beneficiaries, so some charges will be paid by entities that receive little or no benefit from the investments.

If per megawatt hour usage charges are used to recover the cost of the MVP transmission investments this may reduce the benefits realized from those investments if the charges raise the private cost (the sum of the actual generation costs and the usage charges) of some of the resources impacted by the investments sufficiently above their social cost (the actual generation costs), so they are less economic than resources with higher social costs. This kind of outcome is illustrated in Figure 5. Figure 5 shows the same demand and resources that were portrayed in Figure 3 in the previous section, but a $6 per megawatt hour transmission usage charge is assumed to be applied to the western generation, raising the dispatch cost of the $10 per megawatt hour western coal generation above the dispatch cost of eastern coal that has a cost of $15.

Figure 5

Post Investment Off-Peak Dispatch with Local Usage Charges ($6 per MWH)



Thus, at the margin the transmission charge causes generation with a cost of $10 per megawatt hour to be dispatched down and replaced with generation costing $15 per megawatt hour, an inefficiency that slightly reduces the benefits of the transmission expansion. In the example, the transmission expansion reduces the total production cost of meeting load from $58,500 to $38,900 in Figure 3, but the production cost of meeting load rises back to $40,000 in Figure 5 as a result of the imposition of the $6 usage charge, slightly reducing the overall benefits from the transmission expansion.

While there is a potential for per megawatt hour transmission charges to raise the private cost of particular resources in a way that leads to a less efficient dispatch and raises the cost of meeting load within the Midwest ISO footprint, charges structured in other ways can also raise the cost of meeting load. For example, capacity based charges can raise the private cost of generating capacity of particular types or in particular locations sufficiently above the generating capacity's social cost that it is displaced in the market by resources with higher social costs.

An approach of allocating the costs associated with transmission facilities to power consumers can also result in inefficient increases in social costs. Although allocating all of the costs associated with transmission expansion to power consumers will avoid distortions in the short-term economic dispatch of generation resources, differences in how transmission costs are allocated to power consumers in different geographic regions can distort the location decisions of energy intensive load, potentially causing this load to locate in regions with a higher social cost of meeting load because of differences between the private and social cost of meeting load attributable to the transmission charges.

Moreover, the origin of the concerns with the prior Midwest ISO transmission cost allocation methodology was the likelihood that a mismatch between the allocation of costs and benefits from transmission investments would cause the withdrawal of large load serving entities from the Midwest ISO, reducing the social benefits realized from the operation of the Midwest ISO.

While fixed allocations of transmission costs to particular power consumers or generators in a manner that does not depend on their transmission usage avoids the kind of short-run dispatch distortions described above, the potential for the allocation of such sunk costs in a manner that is unrelated to benefits could have a dramatic adverse impact on economic efficiency by deterring otherwise efficient investments.

The best way to avoid inefficiencies arising from the recovery of transmission investments in usage charges is for the entities that will benefit from a particular set of transmission investments to enter into contracts to pay for those investments. When transmission investments are funded in this manner the payments for the transmission investment do not depend on usage, so there is no distortion in marginal incentives and the outcome is equitable because market participants do not need to pay for these investments unless they believe they will realize benefits in excess of the costs.

This approach will not work, however, for funding transmission investments that are not economic or are impacted by some kind of market failure, such as the emission externalities that will motivate some of the transmission investments funded by the MVP methodology.

Our discussion below of the market impacts of the MVP methodology will point out some potential distortions in market outcomes arising from the way the costs of transmission investments are proposed to be recovered in usage charges; however, the implication of our comments is not that there is a simple alternative method of recovering the cost of these investments that would avoid all such economic inefficiencies.

III. MVP Cost Allocation Methodology

A. Core Design Elements

1. Scope and Eligibility

The MVP methodology for allocating transmission costs will be applied to the costs of future transmission construction that is approved in the Midwest ISO planning process for inclusion in Appendix A of the Midwest ISO Transmission Expansion Plan after July 15, 2010 and meets the eligibility criteria for MVPs. MVPs are expected to address regional needs and will be identified via a combined “top down and bottom up” planning methodology. Projects that will not be considered MVP include, but are not necessarily limited to, projects with a total capital cost that does not exceed $20,000,000 or 5% of the net transmission plant of the constructing transmission owner, projects that provide local benefits only, radial facilities used to serve a specific load or interconnect a specific generator, DC facilities that are not under the real-time control of the Midwest ISO or dispatched by the Midwest ISO, the differential cost of underground transmission lines where the driver of increased costs is aesthetics, and other similar exclusions. The cost allocation methodology will not be applied to existing transmission, transmission that is currently under construction or transmission that has been approved in Appendix A of prior MTEP reports.[8]

2. Methodology Overview

The MVP cost allocation methodology would recover the costs of MVP transmission projects through a system-wide usage rate (per megawatt hour) applied to load, an access charge (per megawatt) applied to generation, and the addition of a MVP charge to transmission rates for imports, exports and through-and-out transmission service. 80 to 95% of MVP transmission facility costs would be recovered from load and exports (including wheels) and 5 to 20% would be recovered from generators and imports (including wheels).[9]

There are three major components to the MVP cost allocation methodology: calculation of the transmission revenue requirements that will be allocated using the methodology; allocation of the revenue requirements to the usage charge (load) and access charge (generation) based on allocation factors; and application of a rate design to the transmission revenue requirements allocated to the usage and access charges. The transmission charges calculated under the MVP methodology will apply to all generation and load in the Midwest ISO region, and also imports, exports and wheeling transactions.

The transmission charges will be recalculated annually after applying the cost allocation factors to the annual transmission cost of service for transmission facilities eligible for recovery under this proposal. The cost allocation factors will be recalculated every five

[8] June 3, 2010 Proposal, pp. 3-4.
[9] June 3, 2010 Proposal, p. 6.

years. Transmission rates calculated annually will reflect new transmission investment costs and annual changes in billing determinants.[10]

The Midwest ISO will be responsible for calculating the allocation factors used to assign local area transmission revenue requirements to generation versus load using the MVP methodology. The Midwest ISO also will calculate and collect the charges and distribute these revenues to the relevant Transmission Owners in accordance with the transmission revenue distribution provisions stated in the Transmission Owners' Agreement of the Midwest ISO.[11]

3. Transmission Costs Allocated Under MVP Methodology

The costs recovered under the MVP methodology will be the MVP annual revenue requirements reported by each Midwest ISO transmission owner for projects that meet the MVP criteria. In addition, 10% of the network upgrade costs for Generator Interconnection Projects (GIP) that are 345 kV or above will be allocated and recovered through the MVP usage charge applied to load, exports and wheels.[12]

The MVP usage charge and access charge will be updated on January 1 and June 1 of each year, unless all transmission owners electric the historic accounting treatment (June 1) or the forward looking accounting treatment (January 1). If a Transmission Owner has FERC approval to use forward looking treatment, the rates are effective on January 1st and will be based on projected costs for the coming year subject to an annual true-up. Alternatively, if a Transmission Owner selects historic treatment, the rates are effective on June 1st and are based on transmission costs incurred during the previous year. If there continues to be a mixture of forward looking and historic treatments among Transmission Owners, regional and sub-regional rates would be updated on January 1st and June 1st of each year.[13]

---

[10] June 3, 2010 Proposal, p. 5, 11.
[11] June 3, 2010 Proposal, p. 6.
[12] June 3, 2010 Proposal, p. 5.
[13] June 3, 2010 Proposal, p. 12.

4. Calculation of Allocation Factors

The allocation factors used to divide the annual transmission requirement between the usage and access charges will be based on the Transmission Usage Study released on March 22, 2010 as part of the assessment of the earlier injection/withdrawal cost allocation methodology. The percentage allocation factor for generation will be equal to the overall percentage of local charges borne by generation as a result of the local access rate calculation in that study. The Midwest ISO is still evaluating a range of values for the generator allocation factor: the current value ranges from 5 to 15%. The cost allocation factors will be recalculated every five years.[14]

5. Rate Design

Under the MVP cost allocation methodology, separate rates will be calculated and applied to generation (access), load (usage), and imports, exports and wheels (transmission reservations).

a. Generator Access Charge

New and existing generators interconnected to the Midwest ISO transmission system will pay a monthly access charge. The access charge will be the transmission cost of service allocated to generation (5 to 15% of the annual revenue requirements of MVPs) divided by the sum of interconnected generator capacity and the megawatt quantity of drive-in or through transmission service.[15]

The generator access charge will be applied without regard to whether a generator resource is dedicated to serving load within the Midwest ISO. However, the MVP proposal will also include a dollar for dollar credit against the generator access fee for the

14 June 3, 2010 Proposal, p. 5, 11.
15 June 3, 2010 Proposal, p. 12. In the extreme, the generator allocation percentage could be set to zero, which would eliminate the generator access charge, as in the supporting transmission owners proposal.

MVP transmission cost component of the charges for firm transmission reservations for exports with a term of one year or longer.[16] For pumped storage generators the access charge will be based on the greater of net installed generator capacity or net installed pumping capacity, in megawatts.

Existing generation capacity serving load under existing grandfathered transmission agreements will not pay the generator access charges up to a capped level equal to the existing level of GFA generation. Increases in generation capacity beyond the current level will pay the generator access charge. [17]

Interconnecting generations will be charged the MVP access rate when they become commercially operational, in addition to their network upgrade costs. 10% of the cost of network upgrades for GIP projects of 345 kV and above will be allocated to the MVP usage charge paid by loads but will not be included in the generator access charge. The Midwest ISO will also perform a test to determine whether a new generator is benefiting from network upgrades made by previous generators. A cost sharing methodology is under development to spread some share of the cost of previous network upgrades to the new generator when this situation occurs.[18]

The details of how the access charge would be implemented in the wholesale and retail transmission rates of transmission owners will depend on the transmission rate design of the relevant transmission owner. All generation directly connected to the Midwest ISO transmission system would pay the generator access charge, regardless of whether the generator is explicitly modeled by the Midwest ISO. Behind-the-meter generation and load will be treated in the same as they currently are for purposes of determining pricing zone transmission charges.

Transmission owners may elect to file with the FERC to have the access charge for all generators in their pricing zone directly assigned to all load in their pricing zone. The

[16] June 3, 2010 Proposal, p. 15.
[17] June 3, 2010 Proposal, p. 6
[18] June 3, 2010 Proposal, p. 5, 13, 14.

associated transmission revenue requirement would be collected through the usage rate applied to load in that pricing zone.[19]

c. Transmission Usage Charge

The transmission usage charge will apply to all Midwest ISO loads (i.e. internal load), except load served under a grandfathered agreement specified in attachment P.[20] The numerator in the calculation of the MVP transmission usage charge will be 80 to 95% of the annual transmission revenue requirements of MVPs, plus an estimate of the credits applied to the access charges for generators for the MVP portion of the cost of transmission export service of a year or more in duration, plus 10% of the cost of GIP network upgrades for facilities of 345 kV or more. The denominator in the calculation of the MVP transmission usage charge is an estimate of annual net withdrawals by load, and of the megawatt hours of scheduled out and through service**.** The usage charge under the MVP methodology will be a per megawatt-hour charge applied to each megawatt-hour of power withdrawn from the Midwest ISO grid or scheduled as out or through transmission service.

Pumped storage and other storage resources would be required to pay the per megawatt hour usage charge on their net monthly withdrawals of energy from the transmission system.[21] The billing of the transmission usage charge for station power usage by off-line generators has not yet been resolved, but we will assume that the usage charges will be applied to all net withdrawals. Generators will not pay the usage charge for power they consume as station power when they are on-line; they will be allowed to net this consumption from their energy production for purposes of paying the regional usage charge, which will therefore be based on net injections. We assume that withdrawals by cogeneration facilities will be handled in the same manner (i.e. payments will be based on net withdrawals).

19 June 3, 2010 Proposal, p. 5.
20 June 3, 2010 Proposal, p. 6.
21 June 3. 2010 Proposal, p. 6.

d. Charges for Exports, Imports and Wheeling Service

All drive in, out and through service that is not under an existing GFA will be subject to an import/export charge.[22] The MVP annual revenue requirements will be a separate line item in the transmission rate charged for import, export or through service. The MVP charge will be in addition to existing rates for import, export or through service.[23]

The MVP proposal will include a charge on all firm and non-firm export schedules, without regard to duration. This charge will be equal to the transmission usage charge paid by MISO load. The MVP proposal will also include a dollar for dollar credit against the generator access fee for the MVP charges on export schedules under all firm transmission reservations for exports with a term of one year or longer.[24]

The MVP proposal will also include a charge on all firm and non-firm transmission reservations for imports, without regard to duration.[25] The charge will be equal to the access charge for generators (converted to an hourly rate per month), and will be billed monthly based on the number of hours and the megawatt quantity of the transmission reservation.

Wheel through transactions will pay the reservation access charge for the import portion of the transaction and the usage charge for the associated export transaction schedules.[26]

e. Changes to ARR and LTTR Allocation

Many if not all regional and sub-regional transmission expansions will make additional ARRs/LTTRs feasible. Rules have yet been developed to govern how these ARRs and

---

[22] Absent other agreements with PJM, these charges will be applied to imports, exports and wheels sinking or sourcing in PJM; see June 3, 2010 Proposal, p.15.
[23] June 3, 2010 Proposal, p. 6, 14.
[24] June 3, 2010 Proposal, pp. 14-15. If the percentage of transmission costs allocated to generators was set to zero, this credit would be eliminated.
[25] June 3, 2010 Proposal, pp. 14-15. If the percentage of transmission costs allocated to generators were reduced to zero, the charge on imports would also be eliminated.
[26] June 3, 2010 Proposal, pp. 14-15.

LTTRs will be allocated or taken into account with the MVP methodology for allocating the associated costs, however a Midwest ISO committee is addressing this question and it is envisioned that ARRs/LTTRs made feasible by MVP projects will not be allocated through the process currently used to allocate other ARRs and LTTRs.

B. Unresolved Features in MVP Design

Some elements of the MVP methodology for allocating the costs of transmission are unresolved at this point in time. In this section we list the unresolved elements that we have identified.

- Whether the proportion of MVP transmission costs allocated to generators will be in the range of 5-15% or set to zero.

- Whether generators will pay the per megawatt hour load charge for power withdrawn from the system for station power when they are off line.

- How behind the meter generation and load will be treated for the purpose of collecting MVP transmission charges. The initial thinking is to establish a MW capacity cutoff such that any resources with an installed capacity above the cutoff amount will be subject to MVP charges regardless of whether or not the generation is behind the meter.

These uncertainties do not materially affect our analysis of the market impacts of the MVP methodology.

C. Other Methodologies Evaluated

The Midwest ISO stakeholders have also considered a number of other transmission cost allocation proposals. One of these other proposals is commonly referred to as the Supporting Transmission Owner Methodology. The major elements of that proposal are

100 percent postage stamp charge to recover the costs of Unique Purpose Projects from load on a 12 CP megawatt basis. [27] The Supporting Transmission Owner Methodology includes an export rate, and proposes to charge interconnecting generators 80 percent of the costs for Generator Interconnection Projects at 345 kV and above. [28] We have noted some of the material differences in market efficiency impacts between the Supporting Transmission Owner Methodology and the MVP methodology where relevant in the discussion in section IV.

The Midwest ISO stakeholders also considered the proposal developed by the Organization of Midwest ISO States Cost Allocation and Regional Planning Workgroup. [29] We have not separately commented on this proposal as it represents a combination of the MVP and Supporting Stakeholder methodologies.

Finally, the Midwest ISO stakeholders considered the Highway / Byway proposal. The market efficiency impacts were addressed in addendum B to our April 15, 2010 report, "Evaluation of Midwest ISO Injection/Withdrawal Transmission Cost Allocation Design," and are not discussed again in this report.

---

27 It is our understanding that that the Unique Purpose Transmission Projects are defined in a way that is similar to the Multi-Value Projects whose costs would be recovered through the MVP proposal.

28 See, Supporting Transmission Owners Proposed Compromise for Cost Allocation, revised April 13, 2010.

29 CARP – Main Motion and Proposed Amendments, April 21 and 22.

IV. Evaluation of Market Impacts

A. Overview

This section provides our qualitative assessment of the market impacts of the MVP methodology. We have organized this discussion around the nature of the impacts, rather than the nature of the charges. Section B below discusses the potential impacts of the MVP methodology on the short-run economic efficiency of the Midwest ISO's economic dispatch. Most of the discussion in this section relates to the impact of the per megawatt export and import charges that are one component of the MVP methodology but it also discusses concerns that have been expressed regarding how per megawatt capacity charges collected from generators might impact the Midwest ISO's economic dispatch.

Section C discusses the longer run impacts of the MVP methodology on generator exit and entry. This section focuses in part on the impact of the per megawatt access charges that are another component of the MVP methodology.

Section D discusses the impacts of the MVP methodology on consumers. Although our expectation is that consumers will in the long-run bear almost all of the transmission costs recovered through the MVP methodology, the design of the charges has little direct effect on consumer choices.

Finally, Section E discusses the relationship between the Midwest ISO's ARR/LTTR allocation process and the magnitude of some of the impacts we discuss.

B. Short-Run Dispatch Impacts

1. Impact of MVP Export Charge

The per megawatt hour charge on export schedules that comprises one element of the MVP methodology would potentially distort the economic dispatch between the Midwest ISO and adjacent regions in a manner that raises the nominal cost of meeting load external to the Midwest ISO relative to the social cost (given the transmission investments funded by those charges), but not necessarily relative to the cost of meeting load absent the Midwest ISO transmission investments funded by the MVP charges.[30] The per megawatt hour MVP charge on exports will tend to raise the price of Midwest ISO generation relative to external generation having the same social cost. This will tend to reduce the dispatch of Midwest ISO generation to meet load external to the Midwest ISO, relative to meeting that load with external generation having a higher cost. While the export charge by itself would tend to reduce exports from the MISO, other elements of the design, such as the credit against the access charge for MVP charges associated with long-term transmission reservations, may tend to reduce this effect as discussed further below.

To illustrate the potential effect of the MVP charges on exports suppose that prior to the imposition of a MVP transmission charge on exports the price of Midwest ISO power was $35 per megawatt hour and 1000 megawatts was being exported to PJM, displacing PJM power with costs in excess of $35 per megawatt hour. If the equivalent of a $2 per megawatt hour MVP charge were added to the cost of transmission service for exports, the Midwest ISO exports to PJM would have a cost of $37 per megawatt at the margin. This would be greater than the offer cost of PJM generators with an offer price between $35 and $37 per megawatt hour that had been dispatched down in favor of Midwest ISO generation prior to imposition of the MVP transmission charge, so Midwest ISO exports would fall and would be replaced with PJM generation having a higher social cost.

On the other hand, if exports to PJM were constrained by Midwest ISO congestion, there might be relatively little impact on the level of exports from the imposition of a megawatt hour MVP transmission charge and hence relatively little change in the cost of meeting load either internal or external to the Midwest ISO.

[30] The MVP charge for exports will be a per megawatt hour charge for export schedules, although the proposal is to impose the MVP charge as a component of the current pro forma transmission rate for exports. The proposal is to impose the charge on both firm and non-firm export transmission service of any duration.

It is reasonable to expect that material increases in the export transmission charge are likely to be associated with transmission projects that would reduce regional congestion across the Midwest ISO and hence provide the opportunity for an increase in exports. For example, suppose in the example above that the price of power exported from the Midwest ISO was $35 per megawatt hour prior to the transmission investment but the price of power in the western Midwest ISO was only $28 per megawatt hour, with the difference reflecting the impact of transmission congestion within the Midwest ISO. The effect of the transmission investment might initially be to eliminate congestion across the Midwest ISO, causing the Midwest ISO export price to PJM to fall to $28 for exports of 1000 megawatts, and even with a $2 per megawatt MVP charge added to the cost of all exports, the price exports would be only $30 for 1000 megawatts of exports, so exports to PJM would rise after the transmission investment, displacing higher cost PJM generation. In this illustrative example, however, the true incremental cost of the exports would be only $28, rather than $30, so it could be the case that the imposition of an MVP added to the transmission charges for exports would reduce exports relative to what they would be absent the MVP transmission charges, but increase them relative to what they would be absent the MVP transmission investments.

It is not possible to reach any definitive conclusions regarding the likely actual quantitative effects of the MVP transmission charges on exports because they will depend on the magnitude of the charges, the impact of the transmission investments funded by these charges on congestion patterns, the economics of exports to adjacent control areas absent the transmission charges, and congestion patterns. Moreover, while MVP charges on exports would in isolation tend to reduce the efficiency of the overall economic dispatch, there are other factors such as charges for deviations between day-ahead and real-time schedules, and real-time prices that do not reflect the cost of meeting load with fixed block resources such as gas turbines that may distort the economics of exports in the reverse direction.

A further factor complicating assessment of the practical impact of the export fee is the provision that the MVP proposal will also include a dollar for dollar credit against the generator access fee for the MVP charges made to a generator using firm transmission reservations for exports with a term of one year or longer.

Because the MVP export charge will be credited against the generator access charge of generators using firm service with a term of one year or more to schedule exports, generators having such firm service reservations will effectively pay no MVP charge for exports scheduled using that service; the payments for the exports will be offset by a reduction in the generator access fee. The market effects of this provision are complex.

First, to the extent that the firm service reservations are motivated by a RPS contract between a Midwest ISO generator and an external LSE that requires the physical scheduling of energy to the external load, this provision will have the effect that the generator will pay the access fee but bear no additional costs for scheduling the export transactions. The effects would be similar for a Midwest ISO generator that is a capacity resource in an adjacent region and is required to contract for firm transmission service, except that in the case of capacity resources there might be relatively few exports scheduled absent the MVP charge. There are no adverse market effects associated with these base energy schedules because by assumption they are schedules that would flow absent the MVP charge.

Second, however, with the imposition of the MVP charge on exports, other entities attempting to schedule exports would have to pay the MVP charge for export schedules, while generators with firm transmission service having a term of one year or longer could schedule additional exports without paying the MVP charge, so these generators would be a lower cost source of incremental exports than other entities. This would be the case without the MVP charge as well because they would not pay incremental charges for transmission reservations to the extent they were able to use or redirect their firm service to support the exports. Thus, there does not appear to be any undue market distortion from the credit for MVP export charges. The credit would tend to reduce the distorting effect of the export charge on the short-term economic dispatch to the extent that existing firm service could be used to support exports (and would also remove the revenue generating effect, so the transmission costs would be borne by Midwest ISO load).

Third, if the MVP export charge becomes material (in dollars per megawatt hour) and incremental exports are economic at the margin from the Midwest ISO to one or more sinks over a substantial number of hours over the year, it is possible that the credit would induce generators to purchase additional firm annual transmission service because they would be able to avoid the MVP charges by doing so. This kind of behavior would tend to further reduce the potential distortions in the economic dispatch resulting from the export charge.

Fourth, if the MVP export charge becomes material enough to motivate the scheduling of additional annual firm transmission service, then because the credit for the MVP export charge is limited to generators paying the generator access charge, the export credit will tend to drive the scheduling of exports and the purchasing of firm transmission service to generators able to receive this benefit, rather than financial traders etc. There are some economic distortions associated with this differential treatment of energy market participants whose ultimate impact is hard to predict. The export credit would in any case be reducing the inefficiency that would exist if the full export charge were collected on all exports, but the net effect would be to impose an export charge that generates little or no revenue to reduce the payments borne by internal Midwest ISO load but whose consequence is to limit participation in the export market to generators.

2. Impact of MVP Import Reservation Charge

Under the MVP proposal, a transmission reservation charge would be imposed on all imports of power into the Midwest ISO using either firm or non-firm transmission service. The MVP transmission charge for firm and non-firm reservations for import supply will tend to raise the cost of importing power generated external to the Midwest ISO relative to the cost of internal Midwest ISO generation having the same social cost. This would tend to reduce the dispatch of external generation to meet Midwest ISO load, with imports replaced by generation that is internal to the Midwest ISO having a higher social cost.

This situation is exactly the converse of the example worked through above for the impact of export charges on exports from the Midwest ISO to serve PJM load. With the import charge it is the cost of exports from PJM to serve Midwest ISO load that would be increased, so PJM exports to the Midwest ISO would tend to fall and be replaced with Midwest ISO generation having a higher social cost. As was the case in the context of exports, if imports into the Midwest ISO from adjacent regions are constrained by transmission congestion, then there might be relatively little impact on the level of imports from further increases in the cost of imports due to these reservation charges and hence little impact on the cost of meeting load within the Midwest ISO footprint.

Of course, to the extent that the transmission expansions funded by these charges changed congestion patterns (i.e. reduce the cost of serving some Midwest ISO load with generation internal to the Midwest ISO), there also might be decreases in imports, but this would not reflect any distortion in the economic dispatch attributable to the MVP methodology for allocating transmission charges.

It is not possible to reach definitive conclusions regarding the likely quantitative effects of such transmission reservation charges on imports because they will depend on the magnitude of the charges on import reservations, the impact of the transmission investments funded by the MVP projects on congestion patterns, the economics of imports from adjacent regions absent the MVP transmission reservation charges, and congestion patterns. [31] If the percentage of MVP transmission costs allocated to

---

[31] The charge on imports in the earlier Midwest ISO injection/withdrawal methodology had a neutral effect on the efficiency of the Midwest ISO dispatch because it was accompanied by a similar charge on Midwest ISO generation, so there was not net impact on the relative cost of generation internal and external to the Midwest ISO. That balance does not exist under the MVP proposal as the charge on import reservations is not accompanied by a similar per megawatt hour charge on generation internal to the Midwest ISO. The MVP proposal includes a per megawatt charge on internal Midwest ISO generation, but that charge does not affect the incremental dispatch costs of generation internal to the Midwest ISO. The increase in Midwest ISO energy prices associated with the charge on imports will tend to raise the price of power within the Midwest ISO which will tend to raise the margins of Midwest ISO generation so as to offset the margin impact of the access charge, but the import charge

generators were set to zero, such as in the Supporting Transmission Owner Proposal, it is our understanding that the import charge would also be eliminated and these effects would not arise.

3. Other Effects

This section discusses a number of other concerns regarding impacts of the MVP transmission cost allocation methodology on the Midwest ISO's economic dispatch that we either do not believe will have adverse effects or for which we anticipate that the effects are not likely to be material. First, there have been concerns expressed that the imposition of a per megawatt access charge on Midwest ISO generation (i.e. a capacity charge, not a per megawatt hour output usage charge) will cause the impacted generators to raise their offer prices in an effort to recover these fixed charges. We do not expect this to be the case. We discuss the impact of these capacity charges on generation and entry in Section IV C 4 below, concluding that they could tighten the supply demand balance in the Midwest ISO by resulting in the exit of some generation or by delaying or deterring the construction of new generation, with the nature of these impacts depending on the operation of Module E. While we therefore expect these charges to potentially affect the economic viability of some generation resources by raising their going forward costs, these charges do not affect the incremental costs of generation and therefore would not affect their profit maximizing offer price in the Midwest ISO economic dispatch. If a generator could earn larger profits by raising its offer price, it would have the incentive to do so without regard to the imposition of these capacity charges. [32]

---

also reduces the short-run efficiency of the overall economic dispatch, raising the social cost of meeting load.

Moreover, while we note above that the net impact of the export charge on economic efficiency is muddied by the fact that Midwest ISO real-time energy prices currently probably tend to be too low because they do not reflect the cost of meeting load with fixed block resources, those distortions run in the opposite direction with respect to the import charge which exacerbates the inefficiency associated with the limitations of MISO pricing of fixed block resources.

[32] The only indirect effect of these capacity charges on offer prices that we can envision is in the circumstance in which the capacity charges caused the exit of generation within a load pocket, reducing the competition faced by the owners of the remaining generation and making it profitable for the owners of the remaining generation to raise their offer prices.

A second topic is the impact of the MVP transmission charges on the economics of wheeling power through the Midwest ISO. These impacts are a combination of the effects of the two components -- the charges on imports and on exports. As discussed above, MVP methodology charges tend to disincent both imports and exports and the impact of these charges on wheel through transactions will be the combination of these effects, resulting in an increase in the cost of power wheeled through the Midwest ISO relative to external generation, unless the MVP charges are offset by changes in congestion costs.

A third topic is how the MVP methodology charges on imports and exports might interact with changes in import and export charges by adjacent RTOs or individual transmission owners. If the source balancing authority area were to impose an export charge that was not offset by corresponding benefits in terms of reduced prices from transmission upgrades, that increase in the export charge would tend to reduce exports to the Midwest ISO, just as the Midwest ISO's usage charge on exports will tend to reduce Midwest ISO exports unless offset by reductions in congestion. Conversely, a charge imposed on imports by an adjacent RTO on transmission owners would tend to reduce exports from the Midwest ISO in the same manner as an export fee imposed by the Midwest ISO.

With respect to Midwest ISO exports, increases in charges on imports from the Midwest ISO by adjacent RTOs and transmission owners would tend to exacerbate the impact of the Midwest ISO export charges, again except to the extent that the usage charges are offset by reductions in congestion costs.

C. Generation Exit and Entry Impacts

1. Introduction

The application of the MVP cost allocation methodology to recovery of transmission investment costs could potentially adversely affect generation entry and exit decisions in three ways: 1) raising the cost of generation serving Midwest ISO load, and reducing the supply of generating capacity serving Midwest ISO load in a manner that adversely impacts reliability within the Midwest ISO footprint; 2) failing to insure that sponsors of new generation projects have an incentive to pursue only those generation projects that, together with the transmission investment required to support such projects, provide benefits greater than their costs; 3) distorting generation investment between low and high availability generation in a way that raises the cost of meeting consumer electricity demand within the Midwest ISO footprint.

We anticipate that the first of these potentially adverse effects would be averted by an effective Module E resource adequacy requirement but we discuss it below to help policy makers understand the importance of maintaining effective Module E resource adequacy requirements, and the potential need for changes in Module E to attain this objective as the MVP methodology begins to impact generation investment and exit decisions.

The magnitude of the second and third potentially adverse impact will depend on the magnitude of the generation access charges, the impact of Module E locational requirements, and congestion patterns. The Module E and generation availability impacts are discussed in Sections 2, 3 and 4 below. Section 5 discusses other effects that are perceived to be less likely to be significant in their impact.

2. Reliability/Module E Impacts

The access charges that are one component of the MVP cost allocation methodology will directly raise the costs generators must incur to remain in operation. Absent an effective Module E resource adequacy mechanism, these charges would be borne by generators and would tend to reduce the amount of capacity available within the Midwest ISO footprint until energy margins rose enough to offset these increased costs. Absent changes in shortage pricing values, this reduction in available generation would tend to result in an increase in the likelihood of reserve shortages and ultimately of the need for controlled load shedding.

If the Midwest ISO's Module E resource adequacy requirements work effectively, however, any such increases in generation costs would not lead to an undue reduction in available generation because they would be offset by an increase in capacity payments, either through bilateral contracts or the voluntary auction process. Because energy and ancillary service revenues are not sufficient to cover the going forward costs of the amount of generation required to meet MISO reliability standards, at the margin Midwest ISO generators depend on some form of a capacity payment to cover their going forward costs. The MVP generator access fee is in this respect no different than any other going forward costs that must be recovered from Midwest ISO load, or from external load if the generator is a capacity resource for external load. While there is currently surplus generating capacity within the Midwest ISO footprint, that may no longer be the case by the time material transmission charges are being collected using the MVP methodology so it will be important that Module E work as intended. As discussed in Subsection 4 below, however, this ability to recover the MVP access charges through Module E capacity payments will not be the case for energy only resources that have low capacity values relative to their nominal generating capacity.

The MVP import charge would tend to raise Midwest ISO energy prices relative to fuel prices and other costs and thus also raise generator margins, which would tend to reduce the amount of the generator access charge that would need to be recovered in capacity market charges. However, the MVP import charge benefits generators based on the hours they are on line when imports are on the margin, which will vary across generators depending on whether they are baseload or peaking generators. The combination of the access charge and the import charge will therefore appear to tend to skew the economics of MISO generation towards baseload generation, but these effects are complex and uncertain.

A related topic is the impact of the MVP allocation methodology access charges on the viability of non-Midwest ISO generation located within the Midwest ISO. The collection of access charges from non-Midwest ISO generation located within the Midwest ISO tends to avoid the distortions that would occur if "non-Midwest ISO" generation located within the Midwest ISO could be dispatched to meet Midwest ISO load yet not pay the same access charge paid by "Midwest ISO" generation. Indeed, it is fairly clear that in such a situation, if the access charge was at all material, generation resources located within the Midwest ISO would have an incentive to posture themselves as "non-Midwest ISO" generation to avoid paying the charges while selling power into the Midwest ISO spot market. However, generation contracting to provide capacity to loads located outside the Midwest ISO or to serve RPS requirements outside the Midwest ISO would generally not be able to recover this access charge in their capacity or RPS contract because alternative sources of supply for these external loads would not bear these access charges.

The provision that would allow transmission owners to choose to absorb any MVP charges assigned to generators and recover those costs from their transmission customers in rates is in a sense no different than load serving entities contracting with the generators and agreeing to bear the MVP charges assigned to the generator (which we expect to happen directly or indirectly if Module E operates as intended). Such a policy would presumably be applied on a non-discriminatory basis, i.e. a policy of absorbing the MVP charges of projects constructed by affiliates but not by others would not be permitted. There would also presumably be regulatory review and approval of these policies as it would not necessarily be in the interest of the transmission customers to bear the MVP charges for generation that has contracted to provide capacity to the customers of another transmission owner. Generators would presumably find it more attractive at the margin to locate new resources on transmission systems whose customers absorb any MVP access but we view that as a market outcome rather than a market distortion if it reflects the interests of the transmission customers and the transmission owner.

None of these issues would arise if the generator access charge were set to zero.

3. Inefficient Generation Investment

Another kind of potential inefficiency associated with the MVP allocation methodology is the construction of generation that is lower cost than other generation alternatives once the transmission system is upgraded,[33] but is higher cost than other generation alternatives when the cost of upgrading the transmission system is taken into account. The potential for this kind of inefficiency would be limited if the transmission projects whose cost is recovered through the MVP methodology meet a cost benefit test in the approval process for the transmission projects. The application of a cost benefit test will be complicated in this context, however, by the likelihood that these transmission investments may in part be intended to subsidize the economics of wind generation in the absence of carbon taxes.

Aside from any such intended subsidy, the transmission costs that must be incurred to use wind generation to meet Midwest ISO load will likely vary across transmission and wind projects and if this is not taken into account at some step in either the evaluation process or pricing, consumers may incur excess costs to meet their load with wind generation. Some of the features of the MVP methodology may serve to reduce this potential, particularly the allocation of some transmission costs to generation (rather than assigning all transmission costs to load) but it does not appear that there will be any relationship between the transmission costs incurred to meet Midwest ISO load with wind generation from a particular area or set of projects and the transmission charges paid by the generation utilizing that transmission.

The complete elimination of the generator access charge if zero percent of the MVP transmission costs were allocated to generation might somewhat exacerbate this adverse effect as none of the MVP transmission costs would be imposed on generators, so that generators would not need to recover any transmission costs other than their direct interconnection costs either in the energy market or through contracts (such as renewable portfolio standard contracts). However, it is not clear that this negative impact would be

[33] The transmission costs discussed in this section are not the costs of interconnecting generation to the transmission system but the cost of expanding the transmission system to allow generation within a particular area to be used to meet load elsewhere within the local pricing zone, sub-region, Midwest ISO or elsewhere in the Eastern Interconnection. Some of these costs will be allocated to load under the MVP allocation methodology and a portion will be allocated to generation.

material relative to the MVP cost allocation methodology, given the very limited relationship between the access charges collected under the MVP methodology from the generators served by a particular transmission expansion and the costs of that transmission expansion.

4. Differential Impacts on High and Low Availability Factor Generation Resources

Assigning transmission charges to generators on a per megawatt nominal capacity basis, rather than based on some availability adjusted measure, will not have a symmetric impact on intermittent and conventional generation. As discussed in Subsection 2 above, if Module E works as intended, increases in the going forward costs of generation needed to meet Midwest ISO reliability, such as those associated with the per megawatt MVP access charge, would be recovered in increased capacity payments (rather than leading to generation exit and adverse reliability impacts). When the measurement of generator capacity for Module E purposes corresponds to the net installed capacity on which the transmission charge will be based, there will be symmetry in the impact of transmission access charges on intermittent and conventional generation.

However, this symmetry will not exist for generation that has a much lower Module E capacity value than the capacity rating used to assign transmission charges, as the increase in the transmission charges paid by such a generator would not be offset by an increase in capacity payments. In the extreme case, if wind generation had no capacity value for Module E purposes but was assigned per megawatt MVP transmission charges based on its rated capacity, it would incur the same access charge costs as other generation, but would not recover any of those costs in increased capacity payments, thus providing a material disincentive to investment in such generation or to its continued operation.[34]

[34] We use wind generation as a convenient and relevant example of non-conventional generation with a low availability factor and low capacity value, but the underlying issue extends to all non-conventional generation with low capacity values per megawatt of rated capacity

It is appropriate that generation that does not contribute to reliability during stressed system conditions not receive a capacity payment, but the imposition of a capacity based charge on generation that recovers its going forward costs solely in the energy market would tend to reduce the economic viability of that generation. This effect needs to be evaluated in the context of the transmission investments giving rise to the transmission access charges, however. If the transmission investments that are recovered in the per megawatt access charge are investments that are needed to allow low load factor generation to be dispatched at full capacity, then assigning those transmission costs to those generators based on nominal capacity measures may roughly approximate efficient incentives, i.e. the generation will not be built unless it can recover this portion of the transmission investment needed to accommodate the generation.

In essence, the MVP access charge on generators with low capacity values but able to meet RPS standards must be recovered from the loads contracting for that capacity to meet their RPS standards and the imposition of the generator access charge in effect flows these costs to the loads that contract for the generation to meet their RPS standard requirements.

A potential disconnect in this element of the MVP rate design is that even if it is often the case that interconnection costs depend on nominal capacity, as might be the case with generation remote from load, this will not always be the case and the rate design may have unintended effect of inefficiently deterring the construction of low capacity value non-conventional generation that does not have large interconnection costs.

These potential impacts of the MVP cost allocation methodology on the economics of low availability factor generation would not arise if the percentage of MVP transmission costs recovered from generation were set to zero, as in the Supporting Transmission Owner Proposal.

5. Secondary Impacts

If the future level of transmission access charges is unpredictable, this could impact the riskiness of investments in new generation and/or the willingness of generators to enter into long-term contracts, including capacity contracts, or could lead to some increase in the required margins in such forward capacity contracts to compensate for the added risk and uncertainty. However, this effect is not expected to be material if module E operates as intended as these costs would be borne by load serving entities under capacity contracts. While such contracts would transfer the uncertainty to the loads, the resulting uncertainty is no different from the uncertainty the loads would bear if all MVP transmission costs were directly assigned to loads.

6. Conclusions

Absent the impact of uncertainty regarding the future level of access charges and absent availability differences across generation resources, if Module E works as intended, the increased costs associated with a per megawatt capacity charge would in the long-run be recovered in capacity market payments, ensuring that the generation needed to meet Midwest ISO reliability targets would remain in operation.

D. Impact on Power Consumer Location and Consumption

A flat Midwest ISO-wide per megawatt hour usage charge on power withdrawn from the transmission system would not impact location decisions for power consumers within the Midwest ISO.[35] On balance, since the same per megawatt hour charge would be imposed on all power consumed with in the Midwest ISO, we do not expect the usage charges proposed under the MVP methodology to contribute to material inefficiencies through their impact on the incentives of either end-use consumers or load serving entities.

35 Increased transmission charges would also have an impact on the level of power demand within the Midwest ISO region to the extent that these charges were not offset by reductions in energy prices associated with the transmission investments funded by the transmission charges. It is assumed for the purpose of our assessment that any such net increase in consumer power costs would be small, and have little impact on consumer power demand.

The MVP transmission usage charge in isolation will obviously serve to raise the transmission charge component of the cost of serving load within the Midwest ISO relative to locations outside the Midwest ISO, but whether the overall cost of serving load within the MISO rises as a result of the MVP transmission projects and related cost allocation will depend on the extent to which the MVP transmission projects reduce the congestion costs associated with serving Midwest ISO load. Since the MVP transmission projects are not expected to be economic, the net impact will likely be an increase in the cost of meeting load within the Midwest ISO, reflecting the cost of achieving unpriced environmental objectives.

If the costs of the MVP projects are to be recovered from load, a per megawatt access charge (such as that in the Supporting Transmission Owner Methodology) would be an alternative to the per megawatt hour usage charge used in the MVP methodology. While a per megawatt type access charge would be appropriate from a cost causation standpoint if these transmission projects were incurred in order to more economically or reliably meet peak load, it is our expectation that will emphatically not be the case for the kind of transmission projects whose costs will be recovered through the MVP methodology. It is our expectation that most of these transmission projects will be incurred to permit additional wind generation to be delivered to load during off-peak hours and that the transmission projects will therefore have little or no value in meeting peak load. The issue in assigning these costs to consumers is not cost causation associated with meeting peak load but of recovering from consumers the cost of transmission investments that are uneconomic at current fuel price and emission cost levels with the least distortion in consumer choices.

From this perspective it is our expectation that a per megawatt hour usage charge is likely to induce less inefficient behavior (i.e. behavior that incurs additional costs to avoid charges that reflect sunk costs and cannot be avoided in the long-run or short-run through changes in behavior). Aggregating all of these transmission costs into a charge that is assigned to monthly or annual peak load appears likely to us to induce more such inefficient behavior by individual load serving entities that would incur additional costs through behavior that would serve only to shift these sunk costs onto other load serving entities. We have not attempted to quantify the potential for such inefficient behavior, and it may turn out in practice that the inefficiency would not be material under either allocation methodology for the level of transmission charges that will ultimately recovered through the MVP allocation methodology. On balance, however, we are more confident that the inefficiency will not be material under an approach based on a per megawatt hour charge than a per megawatt charge.

If the percentage of MVP transmission costs allocated to generators were reduced to zero, this would not materially impact the costs borne by consumers in aggregate because if Module E works as intended, the costs allocated to generators would ultimately be recovered from power consumers in any event. There might be a change in which consumers these costs were recovered from, as the costs allocated to low availability factor generation would be recovered from Midwest ISO load in general, rather than the loads contracting with that low availability factor generation. This is an equity rather than market impact effect, unless the resulting cost shift is sufficient to cause some states or transmission owners to leave the Midwest ISO, which would obviously have a material adverse impact on the market.

E. Impact on FTR Allocation

It is very likely that many or all the transmission upgrades whose costs will be recovered through the application of the MVP methodology will make feasible the award of additional auction revenue rights or long-term transmission rights. At present there are no special rules applying to the award of FTRs made feasible by these investments so they would presumably be allocated in the normal Midwest ISO allocation process. The likely result of such a policy would be that potentially valuable auction revenue rights or long-term transmission rights would be awarded to particular load serving entities at zero cost, while the cost of the transmission upgrades that made these auction revenue rights or long-term transmission rights feasible would be recovered from Midwest ISO generation and loads in general.

Aside from the possible equity impacts of such a policy, application of the present rules would fail to apply the value of the transmission upgrades – as either auction revenue rights or long-term transmission rights – as an offset against the cost of such upgrades. This would unnecessarily increase the potential adverse impacts from the application of transmission usage and capacity charges by increasing the net transmission costs that would need to be recovered through transmission charges that potentially distort decisions.

We have previously recommended that the Midwest ISO in some manner monetize the value of FTRs made feasible by the transmission expansions funded by the MVP charges and credit these revenues against the transmission cost of service recovered through the MVP charges.

There is more than one way to accomplish this and the Midwest ISO and its market participants probably have several years before the subject transmission investments begin to impact transfer capability to agree upon the preferred approach. It is an important feature of the design, however, to agree that FTR values will be offset against the costs to be recovered through the MVP charges rather than captured by a few individual load serving entities.

V. Recommendations

We have two primary recommendations regarding modifications to the MVP design. These recommendations relate to the crediting of charges for transmission reservations for exports against the generation access fee and the charge on imports. If the crediting is limited to the MVP component of the export charge and this component is small relative to the firm transmission charge, this crediting may not have much impact. However, if the MVP charge becomes material relative to the firm transmission charge, this crediting mechanism will tend to distort participation in Midwest ISO markets in variety of ways whose full effects are difficult to predict. While most of the direction of these effects on the dispatch will be to reduce the distortions associated with the export charges, this will be because the credit will also eliminate the revenue effects associated with the fee, so the net effects might be little distortion in the dispatch, no MVP revenue , and large distortions in participation in energy markets with secondary consequences that are hard to predict. It appears to us that this scenario has the potential for undesirable unintended consequences.[36]

Second, it is hard to see any positive element of the charge for import reservations as it likely reduces the efficiency of the regional economic dispatch, without any apparent offsetting benefit in terms of revenue recovery since the cost of this charge will fall on Midwest ISO consumers, who are the same consumers who would pay the charges if they were recovered in the transmission usage fee collected from load.[37]

Other Impacts

There are several other elements of the injection/withdrawal methodology whose potential adverse effects are discussed in Section IV but that are not the subject of the recommendations above. The reasons that we attach less importance to these other potential market impacts are briefly summarized below.

First, as discussed in Section IV B the application of transmission usage charges to exports will tend to inefficiently reduce the level of Midwest ISO exports, other things being equal. There are several reasons we do not attach as much importance to this inefficiency as to the issues discussed above. First, both PJM and Midwest ISO apply charges to real-time imports and exports that were not scheduled in the day-ahead market that have a similar effect of discouraging efficient exports from the Midwest ISO, so it is not apparent to us that this change would create a major new problem. Second, the inability of fixed block resources to set real-time prices in the Midwest ISO dispatch

[36] This concern would not arise if the MVP transmission costs allocated to generators were set to zero and the generator access charge eliminated.

[37] This concern would not arise if the MVP transmission costs allocated to generators were set to zero and the import fee eliminated.

likely causes Midwest ISO prices to often be inefficiently low by more than the likely level of these transmission usage charges. Third, the collection of some kind of charge on exports is understood to be important in avoiding inefficient disincentives for participation in the Midwest ISO markets themselves that would result if load serving entities could avoid all of the costs associated with these transmission investments while receiving many of the benefits by withdrawing from the Midwest ISO.[38]

Second, as discussed in Section IV C 3, the access charges paid by generation under the MVP methodology may be far less than the actual transmission costs incurred to allow use of that generation to meet load elsewhere in the Midwest ISO. The MVP methodology is clearly not perfect in this assignment of costs but it is not apparent that it is systematically worse than other methodologies that socialize the cost of these transmission investments, as long as the projects funded by the MVP charges are subjected to some form of cost benefit or other economic analysis somewhere in the transmission project approval process.

38 How material these incentives may turn out to be is very uncertain at this point of time in which it is not known which transmission investments will be funded by MVP transmission charges, the nature of short-term and long-term post investment congestion patterns, the allocation of transmission costs between generation and load, and the actual future pattern of imports and exports between the Midwest ISO and adjacent areas.

Addendum A

Scott Harvey and Susan Pope also have consulted in the past, or are presently consulting on electricity market design and performance, transmission rights or pricing, or market power issues for Allegheny Energy Global Markets; American Electric Power Service; American National Power; Aquila Merchant Services; Avista Corp; California ISO; Calpine Corporation; Centerpoint Energy; Commonwealth Edison; Competitive Power Ventures; Conectiv Energy; Constellation Power Source; Coral Power; Dayton Power and Light,;Duke Energy; Dynegy; Edison Electric Institute; Edison Mission; Entergy; ERCOT; Exelon; General Electric Capital; GPU; GPU Power Net Pty Ltd; GWF Energy; Independent Energy Producers Association; ISO New England; Koch Energy Trading; Longview Power; Merrill Lynch Capital Services; Morgan Stanley Capital Group; New England Power; New York Energy Association; New York ISO; New York Power Pool; Ontario IMO/IESO; PowerEdge; PJM; PJM Supporting Companies; PP&L; Progress Energy; Public Service of New Mexico; Reliant Energy; San Diego Gas & Electric; Sempra Energy; Mirant/Southern Energy; Texas Utilities; Transalta Energy Marketing; Transcanada Energy; Transpower of New Zealand Ltd; TVA; Tucson Electric Power; Westbrook Power; Williams Energy Group; and Wisconsin Electric Power Company.