EVALUATION OF MIDWEST ISO INJECTION/WITHDRAWAL

TRANSMISSION COST ALLOCATION DESIGN

Prepared by Scott Harvey and Susan Pope

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EVALUATION OF MIDWEST ISO INJECTION/WITHDRAWAL 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 injection/withdrawal 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 injection/withdrawal 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 injection/withdrawal methodology.

Section II provides a brief summary of the equity principles that underlie the design of the injection/withdrawal 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.

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[1] This updated report contains an addendum addressing the highway/byway cost allocation methodology that was not included in the original March 5, 2010 report. We have also corrected a number of typographical, grammatical and formatting errors in the body of the original report.

[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 C. 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 injection/withdrawal methodology in Section III benefited from several rounds of detailed comments by Matthew Tackett of the Midwest ISO. Jennifer Curran and Dhiman Chatterjee, also of the Midwest ISO, provided helpful comments on preliminary drafts of this 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 injection/withdrawal methodology, both those elements that are relatively well defined, and some that are still evolving. This section also contains a brief discussion of some of the features of the methodology that may affect the magnitude and variability of the transmission access and usage charges resulting from application of the methodology, which is pertinent to our evaluation of market impacts.

Section IV contains our evaluation of potential market impacts of the injection/withdrawal 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 output 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

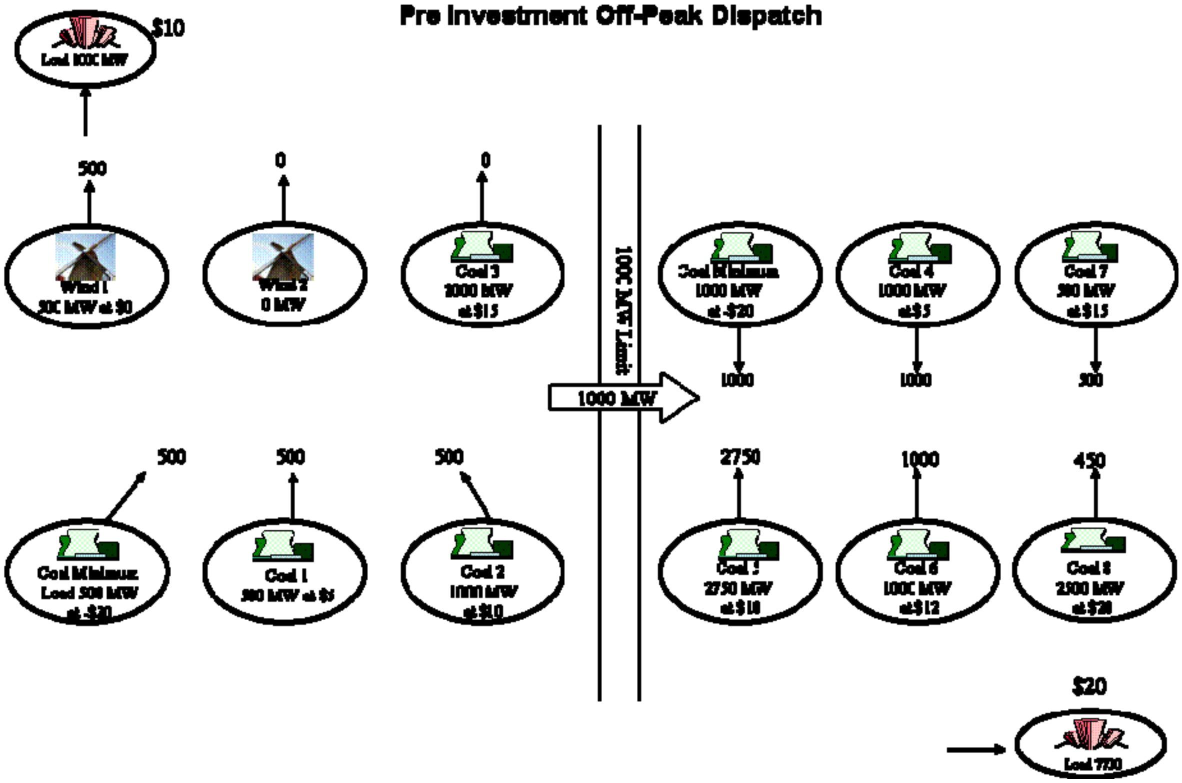
The discussion below of the potential market impacts of the injection/withdrawal methodology for recovering the costs of transmission expansion is premised on an understanding of the way in which transmission expansions impact market prices and congestion patterns. This section provides a brief review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

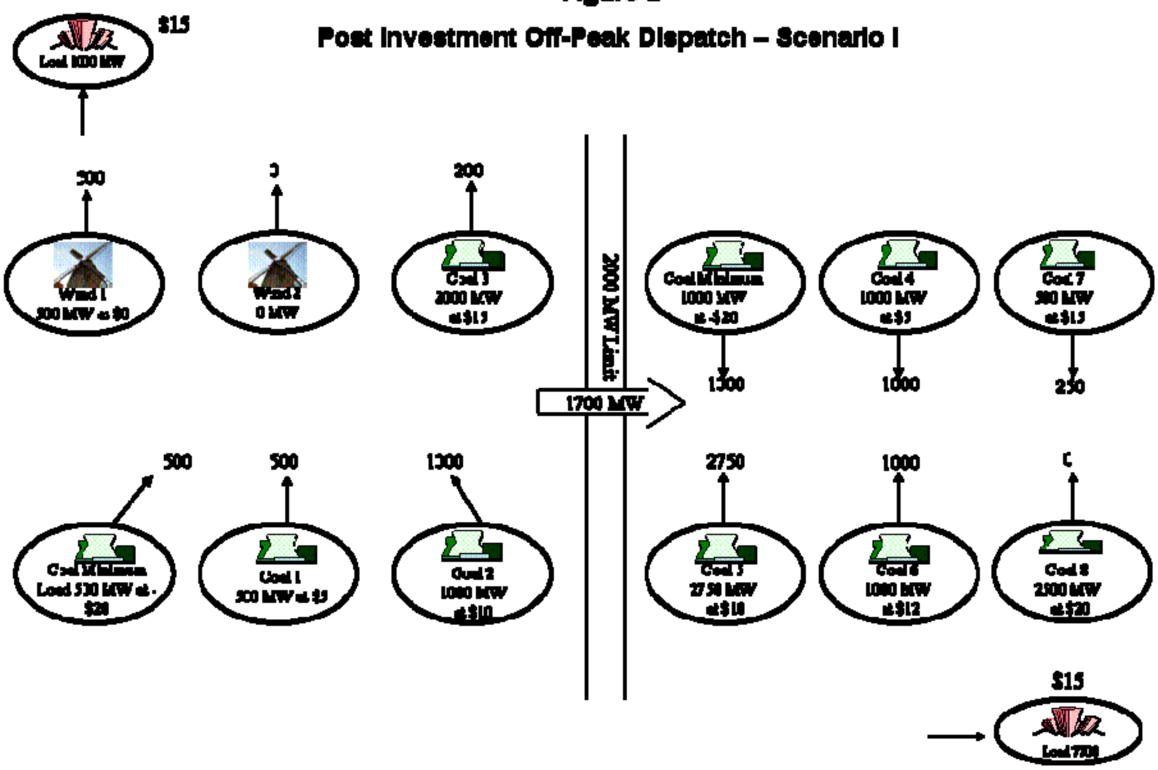
Pre Investment Off-Peak Dispatch



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 $4750 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.

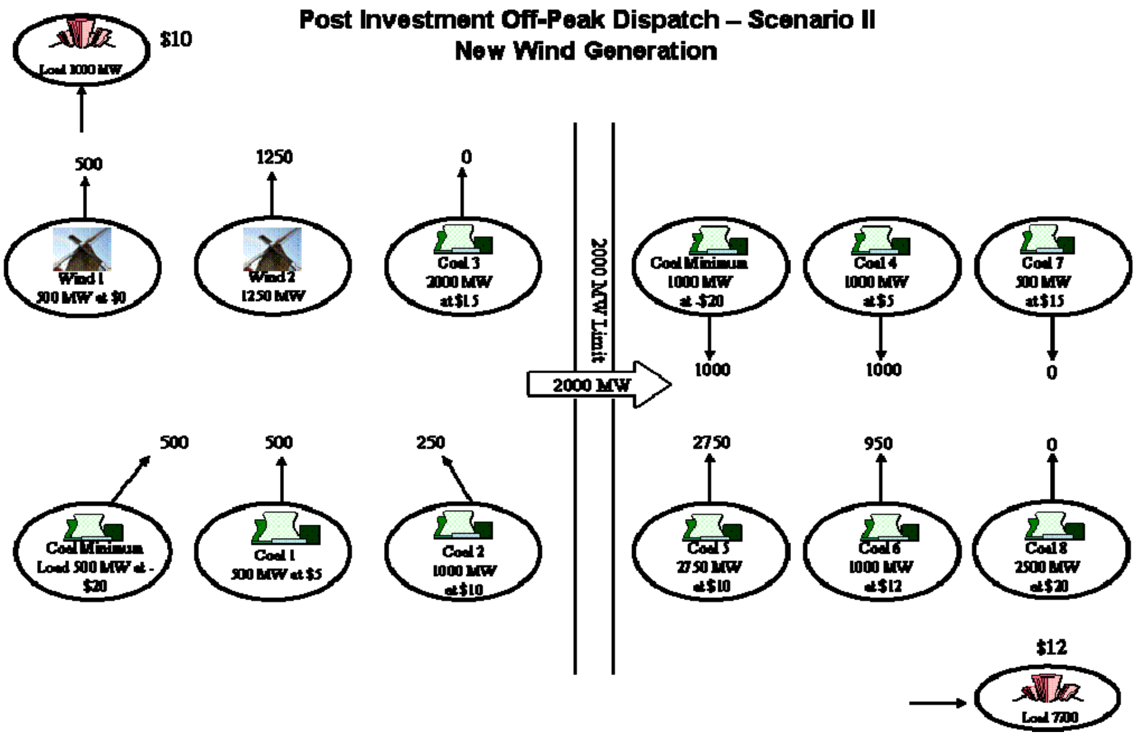
6 450 megawatts of generation at $20 and 50 megawatts at $15 is replaced by generation costs of $10.

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

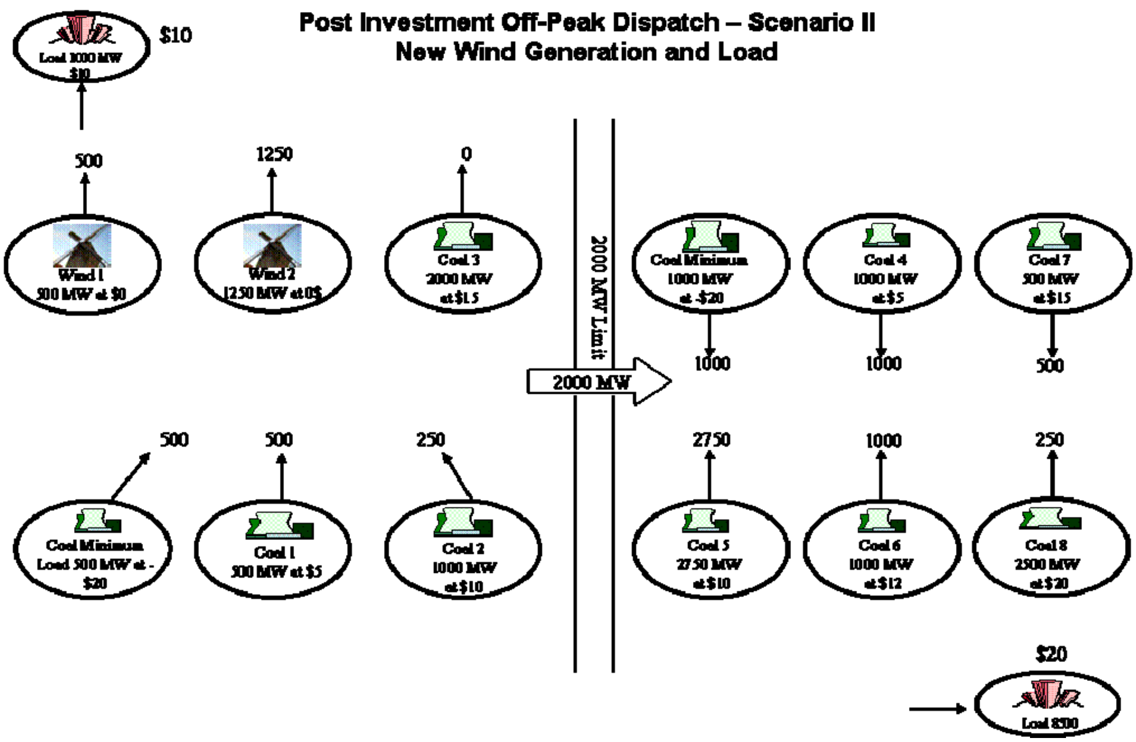


[7] 1250 megawatts of wind have replaced coal costing $10 and $15.

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). 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 injection/withdrawal methodology for allocating transmission costs. The focus of our analysis, however, is not on assessing the extent to which the injection/withdrawal methodology will achieve those outcomes either quantitatively or qualitatively.[8] Instead, the Midwest ISO has asked us to provide a qualitative assessment of the market impacts of the injection/withdrawal 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. The intent of the injection/withdrawal methodology is to attempt to recover the costs of the subject transmission investments through charges that will to a reasonable extent be paid by the entities that benefit from those investments. The principles stated at the beginning of the

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[8] In Section IIIC we provide a brief discussion of how the injection/withdrawal methodology could operate in practice which may be helpful in assessing how the potential equity impacts of the injection/withdrawal methodology could evolve over time.

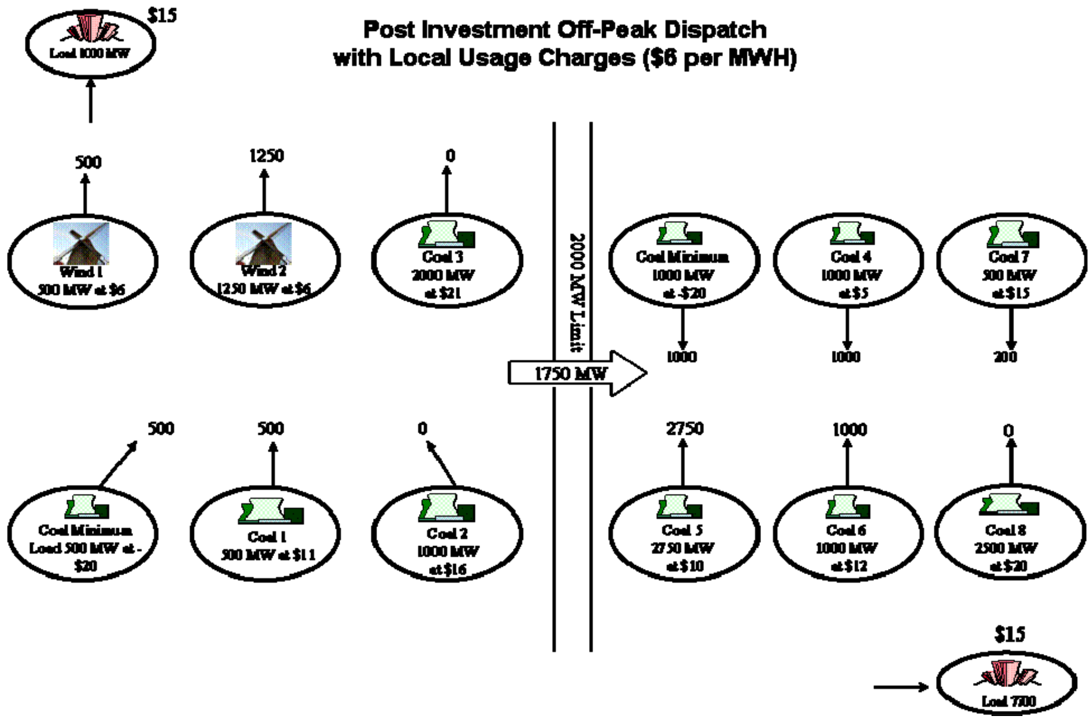
section provide a guide to the design of a methodology that attempts to achieve a nexus between beneficiaries and cost allocation in a manner that aligns with the current situation and experience within the Midwest ISO.

As we briefly discuss in Sections III B and IIIC below, the design of the injection/withdrawal 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. The relationship between benefits and payments under the injection/withdrawal methodology is not the focus of our analysis, however. The focus of our analysis is on the extent to which the way the charges used to recover the costs of these transmission investments are structured will have market impacts that materially reduce the benefits society realizes from those investments.

The charges used to recover the cost of these transmission investments will 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 western coal generation above the dispatch cost of eastern coal with 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 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, 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 injection/withdrawal methodology.

Our discussion below of the market impacts of the injection/withdrawal methodology will point out a number of 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. Proposed Cost Allocation Methodology

A. Core Design Elements

1. Scope and Eligibility

The injection/withdrawal methodology for allocating transmission costs will be applied to the costs of all future transmission construction that is approved in the Midwest ISO planning process in the 2010 Midwest ISO Transmission Expansion Plan or subsequent plans with certain exceptions including, but not necessarily limited to, replacement of plant already in service due to aging or failure, projects that provide local benefit only, 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 transmission that is currently under construction.

2. Methodology Overview

There are three major components to the injection/withdrawal cost allocation methodology: calculation of the transmission cost of service that will be allocated using the methodology; calculation of a set of usage factors for allocating the costs to the local, sub-regional and regional layers; and a rate design applicable to the transmission revenue requirements allocated to the local, sub-regional and regional layers. The transmission cost allocation will be divided into at least two geographical layers: local and regional; the use, in addition, of a sub-regional layer remains the subject of discussion.

The local, sub-regional and regional transmission charges will be recalculated annually by 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 three to five years to reflect projected changes in the transmission system and in generation and load patterns. Transmission rates will be determined annually from these allocation factors, reflecting new transmission investment costs, annual changes in billing determinants, and the true up of over-recovery or under-recovery of the transmission cost of service during the prior year (or years if the true up is spread out over time).

The transmission rates calculated under the injection/withdrawal methodology will apply to all generation and load in the Midwest ISO region, including imports, exports and wheeling transactions. Generation and load will pay three separate transmission rates: local, corresponding to the current pricing zones; sub-regional (possibly), corresponding to the current planning regions; and regional, corresponding to the entire Midwest ISO region. Different billing determinants will be used for charges at each geographic layer.

The Midwest ISO will be responsible for calculating the allocation factors used to assign local area transmission revenue requirements to the local, regional and sub-regional layers using the injection/withdrawal methodology. The Midwest ISO also will calculate and collect the regional, sub-regional and local 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.

3. Transmission Costs Allocated Under Injection/Withdrawal Methodology

The transmission costs allocated each year using the injection/withdrawal methodology will be the cost of service for facilities that have been placed in service plus construction work in progress for any Transmission Owner that has FERC approval to recover the costs of construction work in progress, provided that such costs are for construction projects approved in the Midwest ISO planning process for 2010 or beyond. It is currently assumed that the same basic provisions that exist today will continue under the injection/withdrawal methodology for purposes of determining cut-off dates for transmission costs eligible annually for recovery. Today, 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, including construction work in progress if the Transmission Owner has approval from FERC to recover construction work in progress. If there continues to be a mixture of forward looking and historic treatments among Transmission Owners, regional and sub-regional rates could be updated on January 1st and June 1st of each year.

The injection/withdrawal allocation methodology is designed to allocate the local area transmission revenue requirement associated with a single Transmission Owner. For purposes of the methodology, local areas could be defined to include the systems of more than one Transmission Owner. The current plan is to establish five revenue requirement components for each Transmission Owner: 1) Existing Facilities 2) Voltage Class 1 facilities (future facilities less than 345 kV), 3) Voltage Class 2 facilities (future 345 kV facilities), 4) Voltage Class 3 (future facilities greater than 345 kV, and 5) DC Lines. The injection/withdrawal methodology will be used to allocate transmission revenue requirements falling into Voltage Classes 1-3.

4. Engineering Approach to Calculating Allocation Factors

a. Overview

Transmission costs of service eligible for recovery under the injection/withdrawal cost allocation approach will be allocated among geographic layers based on an engineering analysis of the relative energy flows on the transmission system at the local, sub-regional and regional level. The allocation factors will be calculated separately for the local and regional level and, as stated above, will also include a sub-regional level if there is a sub-regional transmission charge.[9] Within the geographic level, the cost allocation factors will be discriminated by three voltage levels: below 345 kV, 345 kV and above 345 kV for purposes of allocating transmission costs among geographic layers.

The cost allocation factors will be calculated based on 6 generation and load power flow cases: 1) annual summer peak; 2) annual winter peak; 3) 70% of summer peak; 4) 70% of annual winter peak; 5) off peak season, weekday night; 6) off-peak season, weekend day.[10]

The engineering analysis of transmission flows used to determine the cost allocation factors will be updated every 3-5 years as stated above. All flow analysis calculations will be carried out prospectively reflecting transmission investments expected to go into service within the next 3-5 years based on their current status in the Midwest ISO planning and approval process. All load flows will be calculated with all transmission facilities operating in their normal configuration.

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9 It is possible that sub-regional allocation factors could also be used in an intermediate calculation in calculating the regional charges if there is no sub-regional charge. Our evaluation of the Midwest ISO injection/withdrawal methodology is limited to the design in which sub-regions are used both to calculate flows and collect charges.

10 The determination of the number of cases to be used for the flow analysis is not final. The Midwest ISO may expand the number of hourly cases used for the analysis and/or average the flows from the cases using a load duration curve rather than calculating a simple average.

Because the power flow analyses will be prospective, they will be based on a projected generation fleet (including new generation and generation removed from service) and dispatch, forecasted peak and off-peak demand by region, exports and imports forecast based on projected interregional economics and demand-supply balance, and assumed phase angle regulator schedules. Estimates of new generating capacity will be based on executed interconnection agreements and in the event that there is insufficient capacity with such agreements within the 3-5 year window, the additional capacity needed to meet the Midwest ISO capacity requirement will be filled with proposed capacity in the interconnection queue. The model will represent announced generation retirements. Wind capacity will be estimated based on the wind resources in the interconnection queue for the next three years, with upward adjustments if necessary to ensure compliance with State Renewable Portfolio Standard (RPS) mandates.

To determine the load flow for the allocation factors, generation in the prospective model will be dispatched based on economics to meet load without regard to RPS requirements within local areas.[11] The hypothetical generation dispatch will be security-constrained and will include a representation of the impacts on transmission constraints from loop flow from transmission and generation located outside of the Midwest ISO; this includes regional loop flow as well as flows from generation and load that are within the Midwest ISO footprint but are not part of the Midwest ISO. The Midwest ISO ProMod system currently forecasts and dispatches non-Midwest ISO load and generation based on a database provided by the Pro Mod vendor that contains typical data such as economic parameters for generators, including generation not yet in service.

It is envisioned that the generation and load used in the load flow would include all modeled generation and load in the Eastern Interconnection that is included in the Midwest ISO network model. The model would dispatch both internal and external generation economically to serve internal and external load as a whole, and projected net scheduled interchange among RTOs and other balancing authority areas would be

[11] Wind generation will be modeled as fixed injections, i.e. it will not be dispatched, but can be curtailed to avoid transmission overloads.

determined from these dispatch results.[12] Wheel-through transactions will likely be modeled at historic levels. For purposes of the power flow, the Pro Mod engine will estimate wind output based on the wind capacity in service and National Renewable Energy Laboratory (NREL) data. The NREL uses historic weather data to project the expected value of potential wind output by hour, location and hub height at specific sites. The level of wind generation in the powerflow model will obviously depend on whether the six hours selected for analysis are high or low wind generation output hours. The use of average conditions will likely tend to reduce wind generation related power flows relative to the wind generation outputs used to size the transmission investments. The Midwest ISO will continue to rely on information provided by Manitoba Hydro to project hydro output over the 3-5 year horizon of the load flow analysis.

At present it has not been decided whether the allocation factors will be calculated from the flows over all transmission facilities in the engineering analysis, or over only line segments associated with new investment, including those which interconnect the Midwest ISO with adjacent regions. The engineering approach described in this section could be applied in either case.

b. Local Flow Calculation

For the engineering analysis, the Midwest ISO will calculate the local megawatt flow on each local branch attributable to the use of local generation to meet load. The local flow will be calculated based on average load shift factors for load in the pricing zone in each case, weighted average generation shift factors for generation located within the pricing zone weighted based on their output in the economic dispatch for the case, and pricing zone generation and load for each case. The generation and load used in the load flow

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[12] The Pro Mod security constrained dispatch model will yield estimates of net scheduled interchange needed to calculate flows and allocation fractions, but will not provide estimates of gross imports or gross imports to or from the Midwest ISO for use in calculating billing determinants. The current thinking at the Midwest ISO is to estimate gross imports and gross exports that are consistent with the modeled net schedule interchange by applying the assumption that the sum of gross imports and exports (which are the actual billing determinants) will remain constant. The billing determinants would be determined each year based on recent experience.

will be the load and generation physically located within the load zone, i.e. the same generation and load that would pay the local charge.

The local flow on each local transmission branch included in the analysis will be calculated by multiplying the sum of the aggregate generation and load shift factors for the branch by the lower of the pricing zone generation or load for that power flow case (i.e., one of the six or more cases that comprise the engineering analysis).[13]

c. Sub-Regional Flows

For the engineering analysis, the Midwest ISO will calculate the sub-regional MW flow on each sub-regional branch attributable to the dispatch of sub-regional generation to meet sub-regional load. The sub-regional flow will be calculated based on sub-regional load shift factors, sub-regional generation shift factors, and sub-regional generation and load. The sub-regional generation shift factors will be the weighted average generation shift factors for generation located within the sub-region, weighted based on their output in the economic dispatch for the case. The sub-regional load shift factors will be the weighted average shift factors for the load in the case. The generation and load whose shift factors will be used in the load flow will be the load and generation physically located within the sub-region, i.e. the same generation and load that would pay the sub-regional charges.

The sub-regional flow on each sub-regional transmission branch included in the analysis will be calculated by multiplying the sum of the aggregate generation and load shift factors for the branch by the lower of the sub-regional generation or load for that power flow case (i.e., one of the six or more cases that comprise the engineering analysis). This gross sub-regional flow will include the flows associated with local generation and load. The local flows on the branch, per the previous calculation, will be subtracted from

[13] It is not yet completely resolved how flows will be calculated and costs allocated for transmission segments connecting two local pricing zones or two sub-regions but this methodology is not material for our assessment of market impacts.

the sub-regional flow to derive the net sub-regional flow on the branch. All flows and shift factors will have a sign indicating the direction of the flow. These signs will be preserved in adding and subtracting calculated flows.

d. Regional Flows

The gross regional flow on each branch will be determined from the power flow with all transmission facilities in their normal configuration for each of the six or more power flow cases. The gross-sub-regional flow on each branch will be subtracted from the gross regional flow to derive the net regional flow on the branch. Stakeholders and the Midwest ISO are currently evaluating whether or not to also eliminate loop flow in the calculation of net regional flow.[14] This procedure would eliminate loop flow induced by external flows not scheduled through the Midwest ISO, but would include flows attributable to point-to-point or network transmission service, including service schedule at interconnections with neighboring regions.

e. Local, Sub-Regional and Regional Percentage Usages

The next step in the determination of allocation factors will be calculation of the percentage of local, sub-regional and regional usage for each transmission branch. The local, sub-regional and regional flow on each branch is first calculated as the average of the local, sub-regional and regional flows on the branch in each of the six or more power flow cases described above.[15] The percentage of local use on a branch will then be calculated as the ratio of the absolute value of the local flow on the branch to the sum of the absolute values of the local, net sub-regional and regional flows in the branch. The

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[14] If this approach is adopted, the Midwest ISO will calculate the gross regional flows on branches using shift factors calculated for regional load and generation, and then determine regional flow as gross regional flow less gross sub regional flow. This would effectively filter loop flows from the analysis, but would not change the dispatch.

[15] The Midwest ISO used a simple average of the flows on each line across the six load flow cases in a test run of the injection/withdrawal methodology, but a weighted-average of the six cases based on the load duration curve is under consideration for use in the final engineering analysis design.

percentage of sub-regional and regional use of a branch will be calculated in the same way.

f. Mileage Weighted Usage Factors

Local, sub-regional and regional usage factors will be calculated as mileage-weighted averages of the branch-level percentage usages. The local system usage factors will be determined for lines in two voltage classes (i.e., Below 345 kV and 345 kV) by parent sub-region and will be the mileage-weighted average of the local use percentages for each line in a specific voltage class within the parent sub region. The sub-regional system usage factors also will be determined for each of the two voltage classes by parent sub-region and will be the mileage-weighted average of the sub-regional use percentages calculated for each line in a specific voltage class within the parent sub-region. The regional system usage factors also will be calculated in the same way for each of two voltage classes by parent sub-region and will be the mileage-weighted average of the regional use percentages calculated for each line in the specific voltage class within the sub-region. For the "above 345 kV" (i.e. 500 kV and 765 kV facilities) voltage class, a single local, sub-regional and regional usage factor will be determined for the entire RTO; these usage factors will not be calculated separately for each sub-region. Thus, if sub-regions are included in the final analysis, the following mileage-weighted percentage usage factors will be calculated:

- Percentage local usage for transmission facilities below 345 kV within each sub-region.
- Percentage sub-regional usage for transmission facilities below 345 kV within each sub-region.
- Percentage regional usage for transmission facilities below 345 within each sub-region.
- Percentage local usage for 345 kV transmission facilities within each sub-region.

- Percentage sub-regional usage for 345 kV transmission facilities within each sub-region.
- Percentage regional usage for 345 kV transmission facilities within each sub-region.
- Percentage local usage for transmission facilities above 345 kV for the entire RTO.
- Percentage sub-regional usage for transmission facilities above 345 kV for the entire RTO.
- Percentage regional usage for transmission facilities above 345 kV for the entire RTO.

If the final allocation methodology does not include sub-regions, the Midwest ISO will probably continue to calculate the local and regional mileage weighted usage factors by sub-region.

g. Allocation of Transmission Revenue Requirements to Layers

The percentage usage factors applicable to each pricing zone will be used to allocate the transmission revenue requirements for each pricing zone to the local, sub-regional and regional layers. The local revenue requirement used to determine the local injection/withdrawal access rate for a pricing zone will be determined by applying the local usage factor for the pricing zone (determined for the pricing zone's sub-region) to each voltage class revenue requirement within the local area and adding the results across voltage levels. The sub-regional revenue requirement used to determine the sub-regional injection/withdrawal rates will be determined by applying the appropriate sub-regional usage factor to each voltage class revenue requirement in each local area within the sub-region and summing across both voltage levels and pricing zones within the sub-region. The regional revenue requirement used to determine the regional injection/withdrawal rates will be determined by applying the appropriate regional allocation percentage to each voltage class revenue requirement in each local area within the RTO and summing across both voltage levels and pricing zones within the RTO.

The treatment of DC lines has not been finalized, but the current thinking is to place all DC line revenue requirements (not including DC lines already in service) into the regional layer as long as the DC line is an approved project and the Midwest ISO has the dispatch rights and AGC control over the DC line flow.

5. Rate Design

a. Overview

It is envisioned that separate rates and billing determinants will be calculated and applied to generation and load at three different geographic layers: local, sub-regional (possibly), and regional. The regional and sub-regional charges will be calculated on a prospective basis using a mix of forward and historical billing determinants, depending on the rate methodology used by the relevant transmission owners. The local charges may be calculated based on either forward or backward looking billing determinants, depending on the methodology for the local pricing zone.

The current intent is to apply the charges to all withdrawals from the Midwest ISO and to all injections. The charges will apply whether or not generation is serving Midwest ISO load. Imports, exports and wheeling transactions will be charged the same injection/withdrawal transmission usage and access fees as internal load and generation under the proposed rate design. In addition, the current intent is to charge all generators located within the Midwest ISO footprint these same injection/withdrawal transmission rates whether or not they are explicitly dedicated to meeting Midwest ISO load. Thus, as described above, flows from imports, exports and non-Midwest ISO generators and loads are included in the engineering analysis, and the load, capacity and usage of these entities would be included in the billing determinants for the purposes of determining local, sub-regional and regional injection/withdrawal transmission rates.

b. Local Access Charge

The local injection/withdrawal rate will be an access charge to both local generation and load for a pricing zone. The transmission cost of service allocated to the local pricing zone using the engineering flow analysis will be divided by the sum of the twelve month coincident peak demand, net installed generator capacity (or an agreed upon cap below the installed value) for the pricing zone, and some kind of adjustment for exports and wheel-through transactions. The local charge under the injection/withdrawal methodology will take the form of a:

- Per megawatt monthly capacity charge on the net installed capacity of all generators interconnected with the Midwest ISO grid within the local zone;
- Per megawatt monthly peak load charge on load serving entities with load within the Midwest ISO local zone.

The local access charge will be applied without regard to whether a generator resource is dedicated to serving load within the Midwest ISO. For pumped storage generators the local access charge will be the greater of net installed generator capacity or net installed pumping capacity, in megawatts.

New generation resources that connect in the timeframe of the 2010 Midwest ISO Transmission Expansion Plan or beyond, and whose transmission project costs are included in the injection/withdrawal cost allocation method will be subject to a “higher of” test for purposes of determining their local layer transmission charges. For the portion of the Generator Interconnection Project (GIP) Network Upgrade costs that are deemed local for a new generator, the new generator would pay the higher of the local access rate or the rate associated with the new GIP facilities. If the generator pays a higher GIP rate under this methodology, the increment over the local access charge would be the amount required to avoid an increase in the local rate. Thus, the local access rate could increase as a result of other types of transmission projects, but would not increase due to network upgrades associated with GIP projects. Higher-of pricing would not apply to the portion of the GIP network upgrades allocated to the regional layer (or sub regional layer if one exists).

The local access charge will be applied to all transmission service, including hourly service and will be applied to both firm and non-firm service. The local pricing zone transmission costs that are allocated to exports and wheel-throughs will be recovered in the Midwest ISO system wide transmission charge. No local pricing zone transmission costs will be allocated to imports. The system wide transmission charge applied to a point-to-point export, or wheel-through transmission reservation will be in addition to the regional usage charge that will be applied to scheduled megawatt-hours.

The local access charge will be based on the local (and possibly 50% of sub-regional) revenue requirement, whereas the usage charge will be based on the regional layer revenue requirements and, if applicable, 50% of the sub regional revenue requirements. The Transmission Owners will adjust the annual revenue requirements applicable to the local access charge based on external local access revenue received in the previous year.

No exclusions to the local access charge for grandfathered transmission agreements (GFAs) have yet been determined, so our analysis assumes that these charges will be applied to all injections and withdrawals.

The details of how the local 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. Behind-the-meter generation and load will be treated in the same as they currently are for purposes of determining pricing zone transmission charges.

c. Regional Usage Charge

The regional injection/withdrawal rate will be a usage charge to all Midwest ISO supply (imports and internal generation) and load (exports and internal load). The transmission cost of service allocated to the regional layer using the engineering flow analysis will be divided by the sum of the billing determinants for generation injections, load, exports, imports and wheel-throughs. The regional charge under the injection/withdrawal methodology will be a per megawatt-hour charge applied to each megawatt-hour injected or withdrawn from the Midwest ISO grid.

The regional usage charge will be applied without regard to whether a generating resource is dedicated to serving load within the Midwest ISO and without regard to the in-service date for the generating resource. Pumped storage and other storage resources would be required to pay the per megawatt hour usage charge on both their gross injections and withdrawals of energy from the transmission system. 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 injections and withdrawals by cogeneration facilities will be handled in the same manner (i.e. payments will be based on net injections and net withdrawals).

Exclusions to the regional usage charge for grandfathered transmission agreements have not yet been determined.

The Transmission Owners will adjust the annual revenue requirements applicable to the regional usage charge based on external usage charge revenue received in the previous year.

Imports and exports will pay the external usage rate, which will be equal to the sum of the regional usage rate and possibly a sub-regional usage rate (based on 50% of the sub-regional transmission revenue requirement). Wheel-through transactions will pay a double external usage rate since they have both an injection and a withdrawal component.

d. Sub-Regional Access and Usage Charge

A final decision has not been made about whether or not a sub-regional layer will be included in the rate design for the injection/ withdrawal methodology for allocating the cost of new transmission in the Midwest ISO. If such a charge is applied, 50% of the transmission costs allocated to the sub-regional layer will be billed in a per megawatt hour usage charge and 50% of these costs will be billed as a per megawatt capacity charge. The billing determinants for the usage and access portions of the sub-regional charge will be the same as those for the regional charge and local charge, respectively.

6. Changes to ARR and LTTR Allocation

Many if not all regional and sub-regional transmission expansions will make additional ARRs/LTTRs feasible. No rules have yet been developed to govern how these ARRs and LTTRs will be allocated or taken into account with the injection/withdrawal methodology for allocating the associated costs.

B. Unresolved Features

Some elements of the injection/withdrawal 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.

1. Most Important Elements Requiring Resolution

The methodological approach ultimately adopted for the following unresolved issues could have a material impact on the market impacts of the injection/withdrawal approach to allocating transmission costs.

- Whether the rate design/and or allocation factors will include a sub-regional layer as well as local and regional layers.
- Whether the allocation factors determined under the engineering flow analysis will be based on power flows on all branches or just the power flows on new branches, including those which interconnect the Midwest ISO with adjacent regions.
- Whether the billing determinants for the access charge paid for imports, exports and wheeling transactions will be based on the megawatts of reserved transmission service, or on the megawatt hours of scheduled transmission.
- The methodology for allocating the ARRs and LTTRs that are made feasible by the transmission whose costs will be recovered under the injection/withdrawal methodology.
- The determination of the cases to be used for the engineering flow analysis. The current proposal includes six cases, but the Midwest ISO may expand the number of hourly samples used for the analysis.
- The assumptions that will be made regarding wind generation output during the six hours selected for purposes of performing the engineering power flow analyses.

2. Other Unresolved Elements Requiring Resolution

A number of elements of the injection/withdrawal methodology are not completely resolved at present. These unresolved elements include:

- The methodology that will be used to average the branch flows resulting from the engineering flow analysis: a simple average or some kind of a weighted average based on a load duration curve.
- Details of the assumptions that will be used for the engineering analyses of power flows:
  - Assumptions regarding future gas prices and the prospective construction of peaking generation within each local area.
  - Assumptions regarding the relative load, relative fuel prices, and relative wind output of the Midwest ISO and neighboring regions in each of the six or more power flow cases.
  - Whether wheel-through transactions will be held at historic levels in the power flow analyses.
  - Assumptions concerning the impact of the injection/withdrawal charges, and of any associated changes in Midwest ISO LMPs on the dispatch and power flows in the Pro Mod model of the Eastern Interconnection.

- Whether or not loop flow will be subtracted from gross regional flow in the calculation of net regional flow for purposes of applying the allocation methodology. This procedure would eliminate loop flow induced by internal generation and load, import, exports and wheel-through transactions.

- If the final allocation methodology does not include sub-regions, whether the local and regional mileage-weighted usage factors will continue to be calculated by sub-region.

- Whether to place DC line revenue requirements (not including DC lines already in service) into the regional layer as long as the DC line is an approved project and the Midwest ISO has the dispatch rights and AGC control over the DC line flow.

- 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 injection/withdrawal 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 injection/withdrawal charges regardless of whether or not the generation is behind the meter.

Most of these uncertainties do not materially affect our analysis of the market impacts of the injection/withdrawal methodology. More complete specification of the first two bullets relating to the engineering analysis methodology might tend to somewhat reduce the unpredictability of the allocation fractions used in calculating local, sub-regional and regional charges, but we expect that most of unpredictability would remain.

C. Discussion of Potential Allocation Outcomes

The discussion of the potential market impacts of the injection/withdrawal methodology in Section IV below is based in part on our expectations of how the engineering approach could work in practice to allocate transmission costs between local, sub-regional and regional transmission charges. Several elements of the injection/withdrawal methodological design are important in forming these conclusions and expectations.

First, it is important that the engineering analysis used to allocate transmission costs among the three charges is prospective and based on a forward looking simulation model. Thus, while the billing determinants on which the charges will be collected will reflect actual transmission usage, actual generating capacity and estimated monthly peak loads, the charges that will be collected are determined prospectively and the flows in the simulation model need not be closely correlated with those observed on the system in the real world, particularly if the simulation model results are based on a small number of hours. Among other things, this fact has the implication that market participants will not necessarily be able to use their observations and projections regarding real-world power flows to predict the allocation outcomes of the engineering analysis simulation model.

Second, the engineering analysis will not inevitably allocate costs associated with building transmission to allow generation located in a particular pricing zone to serve load elsewhere in the Midwest ISO to the regional charge. This will depend on the flows in the hours of the simulation used to determine the allocation fractions. For example, substantial transmission could be built to allow wind generation to serve load in other regions, but if the specific hours used for the allocation are hours with low expected wind output relative to the transmission capacity, there could be very low regional flows on the local transmission system in these hours, resulting in most of the transmission costs being allocated to local load and generation.

The conditions modeled in the simulation for the specific hours used to determine the allocation fractions will therefore have a very important impact on the allocation outcome. The potential sensitivity of the allocation outcome to the modeling conditions in the selected hours may lead to allocation outcomes that are based on flows that are quite different from the kind of flows that were envisioned in the design of the transmission upgrades and will also make it difficult for market participants to forecast future allocation fractions.

Third, the local transmission charge design in which the sum of the generating capacity and peak load is used for the billing determinants, will tend to limit the transmission costs allocated to load in the zone where new transmission is built to serve new generation. This element of the local transmission charge design tends to ensure that even if large costs associated with building transmission to enable generation to serve load external to the pricing zone are allocated to the local charge through the engineering analysis, the costs will not all fall on the local load. For example, suppose that generation is built in a pricing zone substantially in excess of that need to meet local load, so that generation is four times load. Even if all of the transmission costs associated with allowing that generation to serve load in other zones were allocated to the local zone, only 20% would directly fall on the local load and 40% would fall indirectly on the local load either directly or through the cost of future capacity contracts.

IV. Evaluation of Market Impacts

A. Overview

This section provides our qualitative assessment of the market impacts of the injection/withdrawal 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 injection/withdrawal 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 hour usage charges that are one component of the injection/withdrawal charges but it also discusses concerns that have been expressed regarding how capacity charges might impact the Midwest ISO's economic dispatch.

Section C discusses the longer run impacts of the injection/withdrawal methodology on generator exit and entry. This section focuses in part on the impact of the per megawatt capacity or access charges that are another component of the injection/withdrawal methodology, but some of the important impacts we discuss arise from the usage charges.

Section D discusses the impacts of the injection/withdrawal methodology on consumers. Underlying our view is the expectation that consumers will in the long-run bear almost all of the transmission costs recovered through the injection/withdrawal methodology, but the design of the charges has effects on which consumers bear which costs and also has the potential for unintended adverse impacts on consumers in addition to the direct costs.

Section E discusses the impacts of the injection/withdrawal methodology on forward contracting, an impact which will fall on both generators and power consumers. Finally, Section F 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. Overview

The per megawatt hour transmission charges that comprise one element of the injection/withdrawal methodology would potentially distort the economic dispatch within the Midwest ISO region in two ways. First, if there are material differences in the per megawatt hour sub-regional transmission charges across the sub-regions, these differences would be reflected in the offer prices in the Midwest ISO economic dispatch and cause the Midwest ISO dispatch to differ from the true least cost dispatch and hence raise the cost of meeting Midwest ISO load. Second, the imposition of per megawatt hour regional or sub-regional charges would likely distort the economics of exports from the Midwest ISO in a manner that raises the social 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 those charges.

2. Differential Sub-Regional Charges

One potential element of the injection/withdrawal methodology is a per megawatt hour sub-regional transmission usage charge that would recover the costs of transmission investments whose impact falls within a sub-region. As discussed in Section III, this is one of the elements of the injection/withdrawal methodology that is not yet definite. If these sub-regional transmission charges are more or less similar in magnitude across the three Midwest ISO sub-regions, then they will have little if any effect adverse effect on the efficiency of the Midwest ISO's economic dispatch. However, the reason for including such a charge in the design is the expectation that the sub-regional charges would differ materially across the sub-regions, and in this case there is a potential for the charges to reduce the efficiency of the Midwest ISO's economic dispatch, raising the cost of meeting Midwest ISO load relative to the social optimum.

The source of the potential inefficiency is that a per megawatt hour transmission usage charge imposed on generators based on their net output will affect the generator offer prices in the same way as an increase in their variable generation cost. Hence the imposition of a $2 per megawatt hour sub-regional transmission charge will cause generators located within the sub-region to raise their offer prices by roughly $2 per megawatt hour. [16] This would not effect the efficiency of the Midwest ISO economic dispatch within the sub-region because the offer prices of all generators within the sub-region would rise by the same amount, leaving their relative standing in the Midwest ISO economic dispatch unchanged.

If the magnitude of the sub-regional transmission charge varied across Midwest ISO sub-regions, however, then generator offer prices could rise by different amounts in different sub-regions. This would lead to inefficiency from a social perspective because the change in the offer prices would lead to a change in the dispatch among sub-regions, but the per megawatt hour transmission charge is not a real social cost that varies with output. The real costs of the transmission investments funded by the per megawatt hour transmission usage charges are sunk and unaffected by changes in the economic dispatch. To the extent that a generator with a higher transmission usage charge is dispatched down to accommodate the output of another generator with a lower transmission charge but higher fuel and variable O&M cost, the real social (production) cost of meeting Midwest ISO load will increase.

[16] The actual increase in offer prices could be somewhat greater or less than the amount of the transmission charge if there are differences in the timing of settlements for sales in the Midwest ISO market and payment of the transmission charge, tax consequences or other similar factors.

Suppose, for example, that prior to the imposition of the sub-regional charges the incremental cost of generation dispatched to meet load in sub-regions A and B is $30 per megawatt hour. Then suppose that a transmission usage charge of $1.50 per megawatt hour is imposed in sub-region A, while a transmission usage charge of $.50 is imposed in sub-region B. The generation that was previously on the margin in sub-region A with an offer price of $30 per megawatt hour would now have an offer price of $31.50 per megawatt hour for the same output level, while the similar offer cost of generation in sub-region B would rise to $30.50 per megawatt hour. The Midwest ISO's economic dispatch would therefore dispatch down the generation in sub-region A with the $31.50 per megawatt hour offer price and dispatch up generation in sub-region B with offer prices above $30.50 but less than $31.50. Perhaps the new equilibrium would entail a market price of $31 per megawatt hour.

This outcome is not economically efficient because the generation in sub-region B that is dispatched at $31 per megawatt hour has an actual social cost of $30.50 per megawatt hour plus a transmission charge that is merely a sunk cost, not an incremental social cost,[17] while the generation dispatched in sub-region A at the margin has a social cost of $29.50, and pays a transmission usage charge of $1.50. Hence, generation with a social cost between $30 and $29.50 has been dispatched down and replaced with generation having a cost between $30 and $30.50 per megawatt hour, raising the social cost of meeting Midwest ISO load. Clearly, the larger the difference in the sub-regional charges the larger the potential inefficiency and potential increase in the cost of meeting load.

A second important factor impacting the magnitude of the potential economic inefficiency from the application of sub-regional transmission charges is the extent to which there is congestion between the sub-regions. If there is typically a transmission congestion cost between the sub-regions that exceeds the difference in sub-regional

[17] When the generation in sub-region A is dispatched down and replaced with generation in sub-region B paying the lower transmission charge, no transmission costs are actually avoided by this change in the dispatch because the real costs are the costs of the transmission investment which are sunk. The generation dispatched down in sub-region A will reduce the billing determinants on which the transmission charges will be recovered in sub-region A in a given year but the shortfall will simply be made up in an adjustment of the billing determinants for the subsequent year; there is no change in social costs.

transmission usage charges, then the imposition of differential sub-regional transmission charges on generation will have little if any impact on the Midwest ISO economic dispatch and will serve largely to assign transmission costs to consumers within the relevant sub-region. For example, if the price in sub-region A had been $35 per megawatt hour prior to the imposition of the transmission charge while the price in sub-region B had been $45 per megawatt hour, with the difference in prices reflecting the impact of transmission congestion, then the imposition of differential sub-regional transmission charges would not have impacted the Midwest ISO economic dispatch. With such a pattern of transmission congestion, the price of power would have risen from $35 to $36.50 per megawatt hour in sub-region A and from $45 to $45.50 in sub-region B, but there would have been no inefficient shift of generation between the sub-regions as a result of the transmission charges.

Even if the pattern of transmission congestion does not exactly follow sub-regional lines, congestion will serve to limit the extent to which the dispatch is impacted by the differential sub-regional transmission usage charges.

A final consideration that could tend to reduce the impact of differential sub-regional transmission usage charges on the generation dispatch is if the cost differences between the sub-regions are such that most of the generation that is on the margin is located within a single sub-region so that changes in sub-regional usage charges have little impact on the amount of generation operating in the other region. Thus in the example above, if all the generation on-line during that hour in sub-region B had incremental costs of less than $5, and all the generation that was on the margin with an incremental cost of $30 per megawatt hour was located in sub-region A, then the impact of the imposition of the transmission charges would simply have been to raise the price of power from $30 to $31.50 per megawatt hour across both regions.

3. Regional Export Usage Charges

The second potentially adverse impact on the efficiency of the Midwest ISO economic dispatch relates to the trade off between exports of Midwest ISO generation and generation located external to the Midwest ISO. If there is both a per megawatt hour regional transmission charge on Midwest ISO generation and a per megawatt hour regional transmission charge on exports, these transmission usage charges 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.

For example, suppose that prior to the imposition of a regional transmission charge 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 a $2 per megawatt hour regional transmission charge were imposed on Midwest ISO generation, the price of Midwest ISO generation would rise to $37 per megawatt hour. In addition, there would be a $2 transmission charge on exports, so the Midwest ISO exports to PJM would have a cost of $39 per megawatt at the margin. This would be greater than the offer cost of PJM generators with an offer price between $35 and $39 per megawatt hour that had been dispatched down in favor of Midwest ISO generation prior to imposition of the 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 charge and hence relatively little change in the cost of meeting load either internal or external to the Midwest ISO.

Moreover, one could anticipate that material regional transmission charges might be associated with transmission projects that would reduce regional congestion across the Midwest ISO and hence increase 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. 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 generation charge and a $2 export charge, the price exports would be only $32 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 $32, so it could be the case that the imposition of various per megawatt hour transmission usage charges would reduce exports relative to what they would be absent the transmission usage charges, but increase them relative to what they would be absent the transmission investments.

It is not possible to reach any definitive conclusions regarding the likely actual quantitative effects of the transmission usage charges on exports because they will depend on the magnitude of the regional and sub-regional transmission usage charges, the impact of the transmission investments funded by these transmission charges on congestion patterns, the economics of exports to adjacent control areas absent the transmission charges, and congestion patterns. Moreover, while usage 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.

4. Other Effects

This section discusses a number of other concerns regarding impacts of the injection/withdrawal 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 in comparison to those discussed above. First, there have been concerns expressed that the imposition of a local or sub-regional 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. [18]

Second, there have been concerns regarding the impact of the import usage charges on inter-regional efficiency. If the level of usage charges imposed on imports is the same as the usage charges imposed on generators, then there would be no distortion in the relative short-run economics of dispatching generation within the Midwest ISO or scheduling imports, as both sets of offers would reflect the same usage charge.[19] Of course, to the extent that the transmission expansions funded by these charges changed congestion patterns, there might be decreases in imports, but this would not reflect any distortions in the economic dispatch attributable to the injection/withdrawal methodology charges.

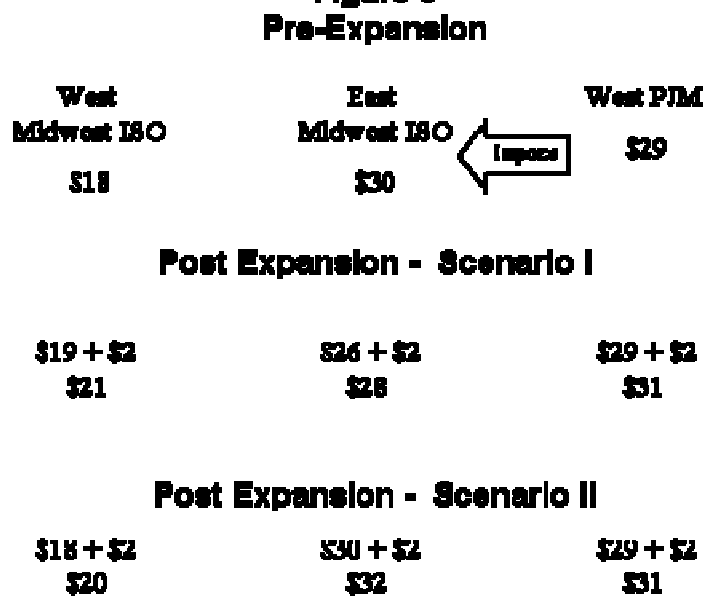
For example, the upper panel in Figure 6 portrays a set of pre-transmission expansion prices and flows in which there is west to east congestion in the Midwest ISO, with eastern prices of $30 per megawatt hour, making it economic to import power from PJM having an incremental cost of $29 per megawatt hour. The prices immediately following the transmission expansion are shown in the lower panel, with an assumed $2 per

[18] 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 remaining generation and making it profitable for that remaining generation to raise its offer prices.

[19] Conversely, however, to the extent that the usage charge on imports is higher than the usage charge on internal generation, then the differential charges would affect the short-term economic dispatch, in much the same way as differential sub-regional usage charges would reduce the short-run efficiency of the Midwest ISO's internal economic dispatch.

megawatt hour regional usage charge in Midwest ISO generation output and on imports from PJM. The price of power in the eastern Midwest ISO has declined to $28, including the $2 usage charge, while the cost of imports from PJM has risen to $31, including the $2 usage charge on imports. Imports would decline in this example, but the difference between the cost of Midwest ISO generation ($28) and PJM imports ($31) is the same as the difference in their social cost ($26 per megawatt hour versus $29 per megawatt hour), so there is no economic inefficiency in the short-run scheduling of imports.

Figure 6



Similarly, the lowest panel in Figure 6 illustrates prices after the construction of new generation and load growth has restored the previous congestion pattern with spot power prices raised $2 per megawatt hour by the assumed regional transmission usage charges (Scenario II in the terminology used above). In this situation imports from PJM would again be economic, and the relative economics of imports would be unchanged by the regional transmission usage charges collected on generation injections and imports.

A third topic is the impact of the injection/withdrawal methodology usage charges on the dispatch of non-Midwest ISO generation located within the Midwest ISO. The collection of injection charges from non-Midwest ISO generation located within the Midwest ISO tends to avoid the distortions in the Midwest ISO's economic dispatch 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 injection charge paid by "Midwest ISO" generation. Indeed, it is fairly clear that in such a situation, if the regional and sub-regional usage charges were 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.

On the other hand, the combination of injection charges and export charges would raise the cost of serving non-Midwest ISO load with generation located within the Midwest ISO in exactly the manner discussed in subsection IV B 3 above regarding exports.

A fourth topic is the impact of the injection/withdrawal methodology usage 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, the injection/withdrawal methodology usage charges have a neutral impact on imports but tend to disincent 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 usage charges are offset by changes in congestion costs.

A fifth topic is how the injection/withdrawal methodology charges on imports and exports might interact with changes in import and export charges by adjacent RTOs or individual transmission owners. We have noted above that the overall impact of the Midwest ISO's charge on imports is neutral between internal and external generation. 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.

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 injection/withdrawal methodology to recovery of transmission investment costs will potentially adversely affect generation entry and exit decisions in four ways: 1) raising the cost of generation, and reducing the supply of generating capacity in a manner that adversely impacts reliability; 2) inefficiently reducing investment in energy storage resources, such as pumped storage, 3) distorting generation location decisions in a way that raises the cost of meeting consumer electricity demand within the Midwest ISO footprint; 4) 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 injection/withdrawal methodology begins to impact generation investment and exit decisions.

We anticipate that the second of these potentially adverse effects is very likely to occur and is quite likely to be significant for reasons discussed below. We therefore think it is very important to address this issue through what we believe are relatively minor adjustments in the application of the injection and withdrawal methodology.

The magnitude of the third and fourth potentially adverse impacts will depend on the magnitude of the differences in the local and sub-regional access charges (and also taking into account the sub-regional usage charges), the impact of Module E locational requirements, and congestion patterns. The Module E, storage investment, generation location, and generation availability impacts are discussed in Sections 2, 3, 4 and 5 below. Section 6 discusses a few other effects that are perceived to be less likely to be significant in their impacts.

2. Reliability/Module E Impacts

The local and sub-regional access charges that are one component of the injection/ withdrawal methodology will directly raise the costs generators must incur to remain in operation. The differential sub-regional usage charges that are another component of the injection/withdrawal methodology will likely tend to directly reduce the net energy market revenues of generation located in sub-regions with above average usage charges.[20] Absent an effective Module E resource adequacy mechanism, these changes would tend to reduce the amount of capacity available within the Midwest ISO footprint until energy margins rise enough to offset the effects of these reduced energy market revenues and 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 reductions in energy market revenues or increased 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.

[20] The extent to which this will occur will depend on congestion patterns between the three sub-regions.

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 injection/withdrawal methodology so it will be important that Module E work as intended.

In addition to the general impact of reduced generator net energy revenues and increased going forward costs on the level of generation that remains in operation within the Midwest ISO footprint as a whole, there is a potential for differences in access charges across local pricing zones (and to a lesser extent differences in access charges and usage charges between the sub-regions), to shift the economics of generator location in a manner that adversely impacts reliability within the local pricing zone or sub-region by reducing the availability of generation within a local pricing zone or sub-region with high transmission costs, while generation resources remain adequate for the Midwest ISO footprint as a whole. It will therefore be important that Module E operate to ensure that local as well as Midwest ISO-wide generation adequacy requirements are met, particularly in local pricing areas or sub-regions in which the existence of multiple load serving entities means that no single entity has an incentive to ensure that the generation needed to maintain local reliability is built or remains in operation. Moreover, because the introduction of the differential transmission access charges for generation within these regions could change the current relative economics of generation operation across local pricing zones, there is a potential for new reliability issues to emerge as the injection/withdrawal methodology charges begin to impact generation investment and exit.

3. Investment in Energy Storage Resources

Under the current formulation of the injection/withdrawal methodology any regional or sub-regional per megawatt hour transmission usage charges would be applied to both the generation injections (i.e. generation) and withdrawals (load) of energy storage resources. If these elements of the injection/withdrawal design are maintained, they will have a profoundly adverse impact on the economics of energy storage resources such as pumped storage because the transmission usage charges would dramatically reduce the margin such resources could earn from a given spread between off-peak and on-peak energy prices. Even if there is no sub-regional charge, and the regional per megawatt hour transmission usage charge on generators were fully reflected in spot power prices, there would be a substantially adverse impact on the economics of energy storage resources.

The reason for the substantially adverse impact is that under the current formulation of the injection/withdrawal methodology, an energy storage resource will effectively pay the regional transmission usage charge three times, so even if spot energy prices rise by the amount of the regional transmission usage charge, the margins earned by an energy storage resource would be dramatically reduced. The reason for the triple impact is that an energy storage resource will pay the regional transmission usage charge for its power injections, pay the regional transmission usage charge for its power withdrawals, and pay the regional transmission usage charge a third time because the charge also would be reflected in the price it pays for its withdrawals.

The potential for serious adverse effects of a per megawatt hour charge on the economics of energy storage resources can be further illustrated with a simple example. For the purpose of the example, we will assume there is a $2 per megawatt hour regional transmission usage charge (on both injections and withdrawals) that is fully reflected in spot power prices. Suppose that absent the per megawatt hour regional transmission usage charge the cost of power would be $20 per megawatt hour off-peak and $30 per megawatt hour on-peak. Also assume that the storage resource has a 10% energy loss and a $2 per megawatt hour variable operation and maintenance cost. Absent any regional transmission usage charges, the energy storage resource would therefore earn a $5 margin on each megawatt hour of power it cycles, paying $20 for each megawatt hour of power stored, selling 90% of the power withdrawn for $30 per megawatt hour when injected into the grid ($27) and incurring $2 per megawatt hour of variable costs. This $5 per megawatt hour margin would be equal to the social gain from the energy shifting, as society would avoid an incremental $27 (.9 * $30) in on-peak generating costs, incur an incremental $20 in off-peak generating costs, and incur $2 in variable operating and maintenance costs for a net gain of $5 per megawatt hour of power shifted from off-peak to on-peak.

With a $2 per megawatt hour regional transmission usage charge on generator output, the off- peak price would rise to $22 per megawatt hour and the on-peak price would rise to $32 per megawatt hour. The pumped storage resource would therefore buy power at $22 per megawatt hour, then sell 90% of that power back at $32 per megawatt hour (netting $28.8 per megawatt hour) for a gross margin of $6.8 per megawatt hour of power cycled. Out of this margin the pumped storage resource would have to cover $2 per megawatt hour of variable costs, a $2 per megawatt hour regional transmission usage charge on withdrawals from the grid and a $2 per megawatt hour regional usage transmission charge on injections to the grid, reducing its margin to $.80 per megawatt hour. The transmission usage charges, however, do not reflect social costs. The social cost is the cost of the transmission which was built, and that investment is sunk. Thus, the social gain from shifting generation from on-peak to off-peak through use of energy storage resources is still $5 per megawatt hour of power shifted in this example, but the private return has fallen to $.80 per megawatt hour because of the application of the various transmission usage charges. Thus, the imposition of the regional transmission charge would substantially reduce the margin generated by such an energy storage resource to cover the investment in such resources or even to cover the going forward costs of such a resource relative to its true social value.[21]

It is important to recognize that the large adverse impact of the injection/withdrawal methodology usage charges on the economics of energy storage resources would still be present even if the transmission investments funded by these transmission charges had large benefits in reducing the cost of power. Suppose, for example, that the transmission investments that resulted in the $2 per megawatt hour charge reduced the cost of power by $8 per megawatt hour on-peak and off-peak so that the off-peak price fell to $14 per megawatt hour and the on-peak charge fell to $24 per megawatt hour, including the $2

[21] It is also possible that the transmission usage charges could, if large enough, even make it uneconomic to shift off-peak power to on-peak, but we do not expect this to be a material effect for such energy limited storage resources.

per megawatt hour transmission charge. The gross margin earned by the hypothetical energy storage resource would be $7.6 per megawatt hour cycled, out of which the pumped storage would have to pay its $2 per megawatt hour variable costs and $4 per megawatt hour of regional transmission charges, for a net margin of $1.6 per megawatt hour of power cycled. In this example the social value of the energy storage would be $5.8 per megawatt hour shifted,[22] which is substantially greater than the return in the market after taking into account the impact of the transmission charges.

The current design of the injection/withdrawal methodology would substantially distort the economics of energy storage resources even in the most favorable of situations, in which the transmission investments reduce the cost of power on-peak but leave it unaffected on-peak. Suppose, for example, that the off-peak price of power falls from $20 per megawatt hour to $14 per megawatt hour (including $2 reflecting the transmission charges) and rises from $30 to $32 on-peak (the increase reflecting the transmission charge). In this case the gross margin earned by the energy storage resource would be $14.8 per megawatt hour shifted,[23] so the net margin after variable operating and maintenance costs and the transmission charges would be $8.8 per megawatt hour shifted. This margin is greater than the margin the energy storage resource would have earned absent the transmission investment, but the social value of the energy storage resource rises to $13 per megawatt hour[24] in the example, so the transmission charges are still serving to dramatically reduce the profitability of the energy storage resource relative to its social value.

These adverse impacts of the current formulation of the injection/withdrawal methodology are very likely to occur if there are significant transmission charges at either the regional or sub-regional level, and without regard to the benefits from the transmission investments. It also appears to us that these adverse effects would be particularly undesirable in the context of large transmission investments to support

22 The social value would be .9 * $22 (the value of the on-peak power excluding the transmission charge which is not a cost) minus $12 (the value of the off-peak power excluding the transmission charge) minus the $2 per megawatt hour variable operating and maintenance costs.

23 The gross margin is .9 times $32 minus $14.

24 The social value would be .9 * $30 - $12 - $2 = $13 per megawatt hour.

increased wind generation, because those investments could increase the social value of such resources as in the example above.

It does not appear to us, however, that these adverse effects of the injection/withdrawal methodology on energy storage resources are fundamental to the design. The undesirable impacts on the economics of energy storage resources could largely be eliminated simply by structuring the transmission charge so that a withdrawal charge is paid only for withdrawals in excess of injections (i.e. net losses) and no charge is paid on the injections that are less than the withdrawals. Table 7 below compares the private and social margins for an energy storage resource across the three price scenarios described above for a methodology in which the transmission charge is imposed on both gross injections and gross withdrawals, versus a methodology in which the charge is imposed only on net withdrawals. Table 7 shows that such a modification would greatly reduced the difference between the social and private profitability of such an energy storage resource.

Table 7
Impact of Regional Usage Charges on Energy Storage Economics

	Base Case	No Price Impacts	Uniform Price Reductions	Off-Peak Price Reductions
		charge on gross withdrawals and injections		
On-Peak Price	$30	$32	$24	$32
Off-Peak Price	$20	$22	$14	$14
Variable O&M	$2	$2	$2	$2
Transmission Charges	$0	$4	$4	$4
Private Margin	$5.0	$0.8	$1.60	$8.80
Social Margin	$5.0	$5.0	$5.80	$13
		charge on net withdrawals only		
On-Peak Price	$30	$32	$24	$32
Off-Peak Price	$20	$22	$14	$14
Variable O&M	$2	$2	$2	$2
Transmission Charges	$0	0.2	0.2	0.2
Private Margin	$5.0	$4.60	$5.40	$12.60
Social Margin	$5.0	$5	$6	$13

4. Inefficient Generation Location Decisions

Transmission access or usage charges that vary by pricing zone or sub-region can potentially distort generator location decisions in a way that reduces the social benefits of the transmission investments that are funded by the access charge. The magnitude of the potential effects are impossible to quantity in the abstract because they will depend on the magnitude of the differences in access charges, congestion patterns, the impact of Module E resource adequacy requirements, the impact of the transmission investments on power prices within the sub-regions and local pricing zones, and the nature of the transmission investments whose costs are recovered in these access charges. If significant differences in access charges across nearby zones are a result of transmission investments that reflect differences in the cost of interconnecting new generation between the zones, the charges may somewhat reduce the benefits derived from the transmission investments. If the significant differences are associated with transmission investments that have little or no impact on the cost of interconnecting new generation or on energy prices, then the charges may directly raise the cost of meeting Midwest ISO load.

Potential Effect of Usage Charge on Generation Entry and Exit

To the extent that there is a per megawatt hour energy generation charge that is applied on a sub-regional basis, material differences in the charge across sub-regions will tend to discourage the construction (or incent the shut-down) of base load generation in the sub-regions with higher per megawatt hour charges,[25] unless the differential charges are offset by corresponding increases in energy prices and other revenues within the sub-region.

The regional usage charge will affect all generation located within the Midwest ISO equally, so would not discourage construction of base load or other generation in one sub-region relative to another. Similarly, if the per megawatt hour charge applied to imported power is equal to the regional charge, the regional charge will not discourage

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[25] Differential per megawatt hour usage charges will also impact non-base load generation, but the revenue impact will be proportionately less the lower the load factor of the generation, so any adverse impact on market efficiency will be greatest for base load, high capacity factor generation resources.

the construction or continued operation of generation located within the Midwest ISO, and serving Midwest ISO load, relative to generation located within adjacent RTOs or balancing authority areas and serving Midwest ISO load.

Potential Effect of Access Charge on Generation Entry and Exit

The level of the local, and possibly sub-regional, per megawatt transmission access charges imposed on generation will potentially differ by local pricing zone (and sub-region). The collection of these transmission charges from generation located within the pricing zone or sub-region will raise the cost of capacity located within the pricing zone or sub-region and hence, would raise the cost of this capacity in either bilateral capacity contracts or voluntary capacity auctions if not offset by higher energy prices. If generators located within the local zone benefit from the transmission upgrades that give rise to the local access charge through higher energy prices, higher capacity prices (or increased dispatch) at their location, then assigning these local transmission costs to the local generators on a capacity basis will not distort remaining in business decisions, relative to the no transmission investment case. Conversely, recovering transmission costs through a per megawatt charge could cause the shut down or discourage the entry of some resources whose operation would be economic without the charge if not offset by increases in energy or capacity prices, or increased dispatch of generators within the affected pricing zone or sub-region. Absent an effective Module E capacity requirement for the local pricing zone (or sub-region), leading to higher capacity prices in some zones, material differences in transmission access costs across pricing zones could shift generation location between pricing zones (or sub-regions).

These potential effects of the injection/withdrawal methodology on the cost of meeting Midwest ISO load can be illustrated with a few relatively simple examples. Consider first a situation in which generation can be located either within pricing zone Red or Blue to reliably serve load within the zones. Suppose that prior to a set of transmission investments the cost of interconnecting generation is relatively high in Pricing Zone Red, $7,000 per megawatt per year, and relatively low, $1,000 per megawatt year in Pricing

Zone Blue. It is assumed that a given generator would earn the same energy and ancillary services margin if located in either pricing zone, and the price of capacity contracts is the same for generation located in either zone, because they are equivalent from a reliability standpoint. This situation is portrayed in the top panel of Table 8, in which the margin requirement of the marginal generator in Zone Red is lower ($55,000 = $25,000 + $37,000 - $7,000) than in Zone Blue ($61,000) because the high interconnection costs deter building generation with going forward costs in excess of $55,000 per megawatt year.

Table 8
Market Impact of Transmission Investments
that Reduce Interconnection Costs

	Pricing Zone Red	**Pricing Zone Blue**
Pre Investment		
Marginal Generator Annual Margin Requirement	$55,000	$61,000
Connection Costs	$7,000	$1,000
Energy and A/S Margin	$25,000	$25,000
Capacity Payment	$37,000	$37,000
Transmission Charge	0	0
Post Investment		
Marginal Generator Annual Margin Requirement	$56,000	$58,000
Connection Costs	$2,000	$1,000
Energy and A/S Margin	$25,000	$25,000
Capacity Payment	$34,500	$34,500
Transmission Charge	$1,500	$500

In the example, assume that a major transmission investment is made in Pricing Zone Red that reduces the cost of interconnecting new generation to $2,000 per megawatt year, which is still slightly higher than in Zone Blue, but much lower than before. This transmission investment will have two social benefits. First, it will greatly reduce the cost of interconnecting generation in Zone Red to serve Zone Red load. Second, it will enable some high cost generation in Zone Blue to be displaced by lower cost generation in Zone Red to serve Zone Blue load.

The lower panel of Table 8 portrays the post investment equilibrium, in which more generation has been built in Pricing Zone Red, and some expensive generation in Zone Blue has been retired. The equilibrium illustrated in the panel assumes a case in which there are no energy market benefits to generators associated with the transmission investment. Energy and ancillary services margins earned by the marginal generators in Pricing Zone Red and Pricing Zone Blue are unchanged by the transmission investment and subsequent changes in the generation fleet. The increased availability of low cost generation in Pricing Zone Red causes the marginal going forward cost of generation in Pricing Zone Blue to fall from $61,000 to $58,000. The transmission investment has produced some social benefits by reducing the cost of the generation needed to meet load within the zones, and it can be seen that the capacity payment required to sustain generation has fallen in both zones. [26]

Table 8 also shows that generation in Pricing Zone Red incurs a $1,500 per megawatt transmission charge, while generation in Pricing Zone Blue incurs only a $500 per megawatt transmission charge, because of the costs associated with the large transmission investment in Pricing Zone Red. Recovering these transmission costs in a per megawatt annual generation charge, slightly raises the cost of generation in Pricing Zone Red, making it slightly less economic than it otherwise would be. For example, absent this charge, generation in Pricing Zone Red with a going forward cost of $57,000 per megawatt year could displace the generation in Pricing Zone Blue with a going forward cost of $58,000 per megawatt year, but this does not happen because of the difference in transmission charges.

A less favorable outcome, in which the transmission charge has a greater potential to distort generator locational decisions, is portrayed in Table 9. In this example, the connection costs and energy and capacity margins are identical between Pricing Zones Red and Blue prior to the transmission investment in Pricing Zone Red. Moreover, it is

[26] The numbers in Table 8 are made up and deriving the equilibrium solution would require specifying a much more complete model of generation supply and congestion patterns, the point is that the reduction in the cost of interconnection will allow the construction of lower cost generation to meet load within the region, driving down the social cost of meeting load and driving down the required capacity payment.

assumed that the transmission investment in Pricing Zone Red that gives raise to a large transmission charge, serves mainly to reduce prices in the energy market for both Pricing Zones Red and Blue as shown in the lower panel. In this example, the imposition of the large per megawatt transmission charge on generation located in Pricing Zone Red raises the cost of generation located in that region, causing a shift to generation in Zone Blue where the transmission charge is lower. In equilibrium, generation in both regions receives the same capacity payment at the margin; however, the imposition of the transmission charge has raised the social cost of meeting Midwest ISO load by shifting to greater reliance on generation located in Zone Blue that actually has a higher social cost but is a lower priced source of capacity because of the lower transmission access charge it must pay. The access charge, however, is not a real social cost that is avoided if the capacity is build in another zone; the payment of the charge is simply shifted to another market participant.

Table 9
Market Impact of Transmission Charges
Not Offset by Market Benefits

	Pricing Zone Red	**Pricing Zone Blue**
Pre Investment		
Marginal Generator Annual Margin Requirement	$61,000	$61,000
Connection Costs	$1,000	$1,000
Energy and A/S Margin	$25,000	$25,000
Capacity Payment	$37,000	$37,000
Transmission Charge	0	0
Post Investment		
Marginal Generator Annual Margin Requirement	$58,500	$62,000
Connection Costs	$1,000	$1,000
Energy and A/S Margin	$20,000	$20,000
Capacity Payment	$43,000	$43,000
Transmission Charge	$3,500	$500

This example does not illustrate the intended operation of the injection/withdrawal methodology; rather, it illustrates the potential for the transmission access charge to incent inefficient generator locational decisions, particularly if the charge is not offset by other benefits from the transmission expansion..

The potential for these kind of inefficient outcomes is also related to the impact of Module E capacity requirements in another way. Part of the potential gain from the transmission investments in the scenario portrayed in Table 8 derived from increased reliance on generation in local Pricing Zone Red to meet load in Pricing Zone Blue, and the inefficiency introduced by the local pricing zone transmission charge was in reducing the shift in generation from Zone Blue to Zone Red. If, however, the two pricing zones were distinct from a Module E resource adequacy standpoint and there were little or no potential to shift generation from one zone to the other to reduce costs, then this would have reduced the benefits from the transmission expansion and also largely eliminated the potential for the access design charge to either result in inefficient shifts in generation or deter efficient shifts in generation.

5. Inefficient Generation Investment

Another kind of potential inefficiency associated with the injection/withdrawal allocation methodology is the construction of generation that is lower cost than other generation alternatives once the transmission system is upgraded,[27] 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 injection/withdrawal 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.

[27] 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. As discussed in Section IIIC, our assessment is that some of these costs will be allocated to the regional and/or sub-regional charges but a portion will also be allocated to the local pricing zone under the engineering methodology.

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 injection/withdrawal methodology may serve to reduce this potential, particularly the allocation of some transmission costs to generation within the local zone (rather than assigning all transmission costs to load) but it does not appear that there will necessarily be a tight 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 that generation.

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

Assigning transmission charges to generators located within a local pricing zone 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 1 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 based local pricing zone transmission charge, would be recovered in increased capacity payments (rather than leading to generation exit and adverse reliability impacts). When the 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 local access transmission 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 local 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.[28]

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 local transmission investments giving rise to the transmission access charges, however. If the local 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 cover this portion of the transmission investment needed to accommodate the generation.

The potential disconnect in this 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.

7. Secondary Impacts

If the future level of local and sub-regional transmission access charges is unpredictable, this could materially impact the riskiness of investments in new generation and/or the willingness of generators to enter into long-term contracts, including capacity contracts,

[28] 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

or could lead to a material increase in the required margins in such forward capacity contracts to compensate for the added risk and uncertainty.

8. 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. Differences in local charges could impact where generation is built and absent locational requirements in capacity market could shift generation out of a region in which it is needed. (It could by chance also shift generation to where it is needed; one can't predict ex ante which way the effect would run).

There is a potential for the injection/withdrawal cost allocation methodology to assign substantial costs associated with regional transmission investments to the local charge. If this occurs in a pricing zone with substantial generation that benefits from the transmission investments, this will not materially distort generation investment decisions. If this occurs in a zone through which transmission is expanded to deliver renewable power to customers in other pricing zones, this could materially increase the going forward cost of generating capacity in those zones, while decreasing energy prices and energy market revenues, thus potentially causing generating capacity needed for reliability to exit until energy prices rose enough to cover the per megawatt charges. It is very hard to predict how these kind of changes would work out over time, but the imposition of a material per megawatt charge in local pricing zones in which the transmission investments either decrease or do not increase energy prices, could lead to inefficient investment patterns.

If the per megawatt level of the local transmission charge is reasonably similar across local pricing zones, there is less potential for the imposition of these charges to materially distort generation investment and staying in business outcomes. However, if substantial transmission investments are made that do not benefit local generation, then charges will deter new investment in the region unless or until they are offset by increases in capacity market charges or energy market revenues.

D. Impact on Power Consumer Location and Consumption

A flat Midwest ISO wide per megawatt hour usage charge on power injected or withdrawn from the transmission system would not impact location decisions for power consumers within the Midwest ISO.[29] Differences in the level of the local per megawatt withdrawal charge[30] could impact power consumer location decisions to the extent that the change in energy prices resulting from the transmission investments is not commensurate with changes in the local transmission charge. Small differences between the benefits from transmission upgrades and the costs assigned would not be material, but large differences in these charges could impact the location of power intensive industry.

A second potential distortion might arise if local transmission charges of a material magnitude are recovered in a peak load based charge but these transmission charges are not accompanied by corresponding peak load related benefits (such as reductions in the cost of contracting for capacity to meet peak demand). In this situation, load serving entities could have an inefficiently large incentive to reduce peak load in order to shift these transmission charges to other load serving entities within the local pricing zone. This consideration is only an issue in local pricing zones in which there are multiple load serving entities. If there is a single large load serving entity within the pricing zone, such as a vertically integrated utility, the recovery of these transmission costs through a peak demand related charges will have no adverse impacts on incentives as the load serving

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[29] 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.

[30] The same consideration applies to material differences in the per megawatt hour or per megawatt sub-regional transmission charges if they are included in the injection/withdrawal proposal.

entity would have no ability to shift the charges to other load serving entities through reductions in its peak load.

This incentive to shift transmission charges assigned to peak load is already present in the current rate design in local pricing zones with more than one load serving entity, so there would be no qualitative change with the introduction of the injection/withdrawal methodology. However, to the extent that the injection/withdrawal allocation methodology is accompanied by a substantial increase in the transmission charges recovered in a charge related to the monthly peak, there may be an increased incentive for one load serving entity to attempt to shift transmission costs to another load serving entity by reducing its monthly peak demand.

This behavior is not inefficient if the reduction in peak-load actually serves to avoid the need for future transmission investments, so whether there is an inefficient distortion in the incentives of load serving entities also depends on the extent to which transmission costs associated with reductions in energy prices or environmental objectives, rather than the transmission costs associated with reliably serving peak load, are recovered in a local pricing zone transmission charge based on peak demand. Thus, if the transmission charges incurred in order to meet an environmental objective are recovered in a peak demand related access charge which is large enough to cause load serving entities to incur costs in order to shift load off-peak in order to avoid the access charge, this would inefficiently raise the cost of meeting Midwest ISO load. Conversely, if the transmission charges are incurred in order to serve peak load reliably, then it would be efficient for load serving entities to incur costs in order to reduce their peak demand and thus reduce the need for to incur such transmission costs in the future.

On balance, although the behavior of consumers and load serving entities could be impacted by the injection/withdrawal access and usage charges in the ways described above, we do not expect the access or usage charges proposed under the injection/withdrawal methodology to contribute to material inefficiencies through their impact on the incentives of either end-use consumer or load serving entities. However, if there are unexpected changes in the pattern of transmission usage this could cause unexpected changes in the engineering approach allocation factors so that substantial transmission costs that were incurred with the expectation that they would be recovered in a regional charge are instead be assigned to the local transmission charge. In this situation, it is possible that particular pricing zones could be impacted by local transmission charges that are much larger than expected, large relative to past levels and large relative to the levels in adjacent regions, and this could lead to material impacts of the kind described above.

E. Impact on Forward Contracting and Retail Procurement Processes

1. Standard Forward Contracts

The imposition of a per megawatt hour transmission usage charge on generation injections could hinder forward contracting for power in standard forward power markets to the extent that the year to year variations in the generator injection transmission usage charge are not reasonably predictable in the time frame in which the forward contracts are entered into. [31] A per megawatt hour transmission usage charge on generation would directly impact the market price of power by raising the incremental cost of supplying power, either from Midwest ISO generation or imports. It would also raise the cost of covering standard forward contracts with purchased power, by raising spot power prices by the amount of the per megawatt hour transmission usage charge. If the amount of the generation transmission usage charge were established within a relatively narrow band a few years in advance, so that it could be predicted and accounted for by buyers and sellers entering into forward contracts, the potential adverse impact on the quantity of forward contracting would be reduced.

[31] The imposition of a per megawatt capacity charge would potentially impact forward contracting in the energy market by marginal generating resources and would likely impact forward contracting for capacity, but the imposition of a per megawatt hour charge on generator output would have the most direct impact on standard forward contracting in the energy market by directly raising the incremental cost of covering such contracts through generation and raising the cost of covering them financially by raising the market price of power.

Although consumers and generators could contract forward based on their expectations regarding the likely level of the of the transmission usage charge, if the transmission charge design does not allow the amount of the generation transmission usage charge to be established in advance, the transmission charge design might materially reduce forward contracting because the uncertainties regarding the future magnitude of the regional transmission usage charge on generator injections could swamp the potential benefits for both consumers and generators from forward hedging, resulting in a bid ask spread for future years that would discourage forward hedging.

While greater uncertainties will likely exist regarding gas prices than those associated with likely levels of the transmission usage charge, suppliers can hedge gas price uncertainty in forward gas markets but there is no mechanism, other than Midwest ISO policy in setting the transmission injection usage charge, that would enable suppliers to hedge against large changes in the transmission usage charge. There is also no mechanism for coal fired generation to hedge the possible cost of future CO2 taxes, a factor which may limit very long-term forward contracting supported by coal fired generation assets. Even in this case, however, the uncertainty on the cost side is material only for the long-term and only for generating assets with CO2 emissions. There is a potential for the design of the injection/withdrawal methodology to deter even forward contracts extending only a few years into the future if the term extends across periods for adjustments in the allocation fractions.

These uncertainties could be particularly large in the initial years following implementation of the injection/withdrawal methodology when there is no history to predict the likely future level of the transmission usage charge or changes in the allocation fractions. Until the flow-based allocation methodology has been implemented over a period of time and its effects are fully understood, there will be uncertainty regarding the future level of these transmission usage charges. This uncertainty regarding the level of per megawatt hour transmission usage charges would arise from uncertainties associated with the fraction of transmission investment costs assigned to the regional or sub-regional per megawatt hour usage charge,[32] uncertainties about whether future transmission projects to be recovered in the regional rate will go forward, uncertainties regarding the timing of the introduction of new transmission costs into the transmission cost of service recovered through the usage charges, the potential for changes in the application of the methodology, and the results of any regulatory or legal challenges to the application of the usage charges.

On the other hand, to the extent that the transmission investments funded by the transmission usage charges serve to reduce transmission congestion and reduce the cost of generation investment, they would tend to reduce forward power prices and these effects could more than offset the impact of a withdrawal charge on forward power prices.

The potential for a generator transmission usage charge may already be impacting very long-term forward contracting and will likely do so until either the form of the transmission usage charge is resolved or commitments are made regarding the time frame within which any such transmission usage charges on generators will be applied. While the imposition of such an injection based transmission usage charge will advantage or disadvantage the parties to existing contracts, in our view there is no way to avoid this. Changes in costs are one of the uncertainties borne by the contracting parties and there is no principled way to assess which uncertain future costs were reflected in forward prices, other than the terms of the contracts. The best way to minimize any adverse impact of the injection/withdrawal methodology on future forward contracting is to expedite the resolution of the design of generation injection charges and perhaps provide for a time lag for the introduction of changes in either the transmission usage charges themselves or unpredictable changes in the allocation fractions so that changes in the transmission usage charge generators would not greatly impact near term forward contracting.[33]

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[32] This uncertainty would be reduced once the fraction was established for the 3-5 year period but would become pronounced as the end of each 3-5 year period approaches. Absent any clear rules governing the structure of the load flow used to calculate the allocation fractions, it is not clear how they could be forecasted.

[33] By near-term forward contracting we are not referring to forward contracts entered into in 2010, as any transmission usage charges on generation injections are unlikely to be material for several years. Our

It is also important to be clear that our concern is focused on the impact of unpredictable transmission usage charges on standard forward financial contracts such as those traded and cleared on exchanges, not customized long-term contracts for the output of a specific generator plant. Individualized contracts for the output of a specific generator plant can provide for adjustments up or down to the purchase price for changes in the level of the usage charge relative to an expected level. For similar reasons, we are not particularly concerned with the impact of unpredictable local transmission access charges (the converse of the unpredictable regional transmission usage charges) as bilateral capacity contracts can include provisions providing for the adjustment of the purchase price for capacity to account for these changes, or can choose not to include such provisions, as negotiated by the buyers and sellers.

2. Provider of Last Resort Procurement

The potential uncertainty regarding both per megawatt hour and per megawatt generator charges could also affect participation in provider of last resort power procurement processes, as it would create uncertainty for suppliers bidding in these auctions regarding the costs they would incur in covering those retail contracts. While there are other unpredictable costs in these retail auctions, many of those tend to vary both up and down from month to month so the range in outcomes summed over the duration of the contract is more predictable.[34] Errors in predicting the Midwest ISO transmission charge could be cumulative, however, because the same error would impact every future month. This would most obviously be the case with respect to errors in projecting the fraction of transmission investment costs to be recovered in the regional rate, but might also be the case with respect to the general level of future transmission investment.[35] This would also

concern is with the impact on forward contracts extending more than a year or two into the future when we get into the 2015 or 2016 time frame when these regional transmission usage charges might or might not be material.

[34] Such as ancillary service charges, load shape costs, and Schedule 1 charges.

[35] Litigation that delayed transmission projects and thus reduced the level of investment might delay investments for a substantial period of time, thus causing the deviations from the expected level of charges to be correlated over a prolonged period of time.

create contract stress because once Midwest ISO charges diverge from the level expected at the time the contract is entered into they would likely continue to diverge.

The application of a per megawatt hour transmission usage charge on generators could therefore increase the prices at which suppliers would bid into retail auctions, since the bid would reflect the cost of expected future transmission usage charges and possibly a premium to cover the risk of unexpected increases in the transmission usage charge. The transmission usage charge would also impact generators with outstanding retail obligations (and conversely benefit consumers covered by existing retail contracts), similarly to how it would impact generators and consumers with outstanding forward contracts, as described above.

To the extent that the transmission investments funded by the transmission usage charges reduce the price of power at the location covered by a retail contract, this would offset the financial impact of the transmission usage charge on suppliers that would buy power to cover the obligations they incur in a provider of last resort procurement process, so for such entities the net impact on participation in forward retail auctions would depend in part on the extent to which the allocation methodology assigns transmission usage costs in a manner that they are offset by the benefits from the transmission upgrades. However, to the extent that such entities seek to hedge their price risk by entering into forward contracts, they will be impacted by uncertainties regarding the future level of the per megawatt hour regional and possibly sub-regional transmission usage charges on the willingness of generators to enter into forward contracts. Thus, the cost of procurement contracts may not rise relative to forward power contracts, but would nevertheless be elevated by the impact of the transmission cost recovery mechanisms on the pricing and availability of standard forward power contracts.

Because such forward retail procurement processes are effectively non-standard forward contracts, the states or utilities undertaking such procurement processes have some ability to mitigate these impacts by including provisions in their procurement contracts that allow for adjustments to reflect the impact of future changes in transmission usage charges on either injections or withdrawals. The ability of the states and utilities to allow for these kind of adjustments, however, will not avoid the potential adverse impacts of uncertain transmission usage charges on the pricing of standard forward contracts which participants in the procurement processes may want or need to use in part to hedge their cost of supplying power under the procurement contracts.

F. 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 injection/withdrawal 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, it 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.

V. Recommendations

We have four primary recommendations regarding modifications to the injection/withdrawal design. These recommendations relate to the treatment of energy storage resources, the application of sub-regional usage charges, the adjustment over time in regional usage charges, and the award of FTRs made feasible by transmission investments funded through the injection/withdrawal charges.

Energy Storage Resources

As discussed in Section III C 4, the application of transmission usage charges to energy storage resources could in effect have a triple impact adversely impacting their long run economics, and perhaps sometimes even their short-term usage. This result is not only economically inefficient, but appears likely to undermine rather than support integration of intermittent generation resources. Moreover, it does not appear to us that this usage charge structure for energy storage resources serves any equity or policy objective. The adverse impact of the injection/withdrawal methodology on energy storage resources appears to be incidental; it does not appear to us to be fundamental to the design of the injection/withdrawal methodology and the undue adverse impacts could be avoided by imposing the usage charge only on the net energy consumption of such energy storage resources.

Sub-Regional Usage Charges

If the sub-regional usage charges applied to generation under the injection-withdrawal methodology are material, they have the potential to reduce the efficiency of the Midwest ISO's economic dispatch in a way that would raise the overall cost of meeting Midwest ISO load. On the other hand, if the sub-regional usage charge is not material, it is not clear that the sub-regional distinction is needed in order to strengthen the link between the cost allocation and the beneficiaries of the transmission expansion, especially in light of the added complexity introduced in the administration of the sub-regional component of the charge. In light of these considerations, we recommend that the group consider whether the need for the sub-regional generator usage charges are essential to the design and if not, to eliminate them..

Adjustment Over Time in Generator Usage Charges

There is a potential under the current design for substantial and potentially largely unpredictable changes in the allocation fractions used to assign transmission costs to the local, regional and sub-regional generator charges. When the magnitude of the transmission costs being recovered in these charges becomes material, the periodic changes in the regional generator usage charges (and the sub-regional generator charges if they are retained as part of the design) will materially impact energy prices, and will hinder forward contracting within the Midwest ISO footprint based on standard forward financial contracts if the changes in the allocation fractions and hence generator usage charges is unpredictable. We recognize that changes in the allocation of transmission costs to reflect changes in usage patterns is an equity objective that is sought with the injection/withdrawal methodology but it would be desirable to make design choices that reduce the potential for sudden unpredictable changes in allocation fractions and generator usage charges to the extent consistent with achieving the perceived equity objectives.

FTR Awards

Absent changes in the Midwest ISO ARR/LTTR allocation process, the transmission expansions funded by the local, sub-regional and regional transmission charges will make feasible the award of additional FTRs, that will be allocated to particular load serving entities at zero cost in the Midwest ISO allocation process. In the long run, it may be the case that most of the economic benefit from these transmission expansions will be reflected in the value of the FTRs made feasible by those investments. [36] Aside from possible equity impacts of such an outcome in which the costs of the transmission investments are recovered broadly from Midwest ISO market participants through the injection/withdrawal charges and the benefits are largely accrued by a small set of entities that are awarded the FTRs made feasible by those investments, such a design unnecessarily increases the transmission costs that need to be recovered through the injection/withdrawal charges and hence magnifies the potential market impacts. All of the potential economic efficiency reducing impacts of these charges discussed in Section IV would be reduced in magnitude to the extent that less transmission cost needed to be recovered through these charges.

[36] This is Scenario II as discussed in Sections II B and IV C6 above.

This could be accomplished by in some manner withholding the transfer capability made feasible by the transmission expansions from the FTR allocation process and offering it for sale in auctions with the auction revenues credited against the transmission cost of service recovered through the injection and withdrawal methodology. 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 important an important feature of the design, however, to agree that FTR values will be offset against the costs to be recovered through the injection/withdrawal charges rather than captured by a few individual load serving entities.

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 regional transmission usage charges to generation injections and 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 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.[37]

Second, as discussed in Section IV C 3, there is also a potential for the local capacity charges on generators to inefficiently distort generator location decisions across local pricing zones with materially different local transmission charges. However, there is also a potential for a system in which no charges are assigned to local generators to inefficiently distort generator location decisions across local pricing zones with very different costs of building the transmission needed to meet load with generation within the local pricing zone. Thus, the capacity charges paid by local generation under the injection/withdrawal 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 injection/withdrawal 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.

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[37] 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 the injection/withdrawal methodology transmission charges, the nature of short-term and long-term post investment congestion patterns, the allocation of transmission costs between local and regional charges, and the actual future pattern of imports and exports between the Midwest ISO and adjacent areas.

Addendum A

Market Impacts of a Highway/Byway Transmission Cost Allocation Methodology

This addendum evaluates the market impacts of a "highway/byway" transmission cost allocation methodology. Our understanding is that the primary difference between a "highway/byway" cost allocation methodology and the original injection/withdrawal cost allocation methodology discussed in the body of this paper is that a highway/byway methodology would assign transmission charges only to loads. A highway/byway cost allocation could be combined with a variety of rules for defining local (byway) versus regional (highway) costs; the rules for this division of costs are independent of the fundamental choice between the injection/withdrawal and highway/byway methodologies. To allow us to focus on the key differences between the injection/withdrawal and highway/byway methodologies rather than the many variations in how costs could be divided between local and regional, we will assume for the purpose of our analysis that the same methodology would be used under the highway/byway methodology as under the injection/withdrawal methodology to: 1) determine the transmission revenue requirement by pricing zone that would be eligible for recovery through these charges and 2) assign this revenue requirement to the regional or local level.

We further assume for the purpose of our analysis that under the highway/byway methodology the costs defined to be local would be recovered in a per megawatt charge on the 12 coincident monthly peak loads of each entity serving load within the pricing zone, and that the costs defined to be regional would be recovered on a per megawatt hour charge on each megawatt withdrawn from the transmission system by load either internal or external to the Midwest ISO. With these assumptions, the primary differences between the highway/byway and injection/withdrawal methodologies are that the highway/byway approach would not allocate a proportional share of the local charge to generators within a pricing zone on the basis of each generator's megawatt capacity and would not include either a per megawatt or per megawatt-hour sub-regional charge.

As in our original report, we have grouped the discussion of the market impacts of the highway/byway cost allocation methodology into five categories: Short-run Dispatch Impacts, Generation Exit and Entry Effects, Power Consumer Location and Consumption Impacts, Impacts on Forward Contracting and Retail Procurement Processes, and FTR Allocations. Each category is discussed below.

Short-run Dispatch Impacts

In our March 5, 2010 paper, we identified two potential adverse impacts that the Midwest ISO's original injection/withdrawal methodology could have on the efficiency of the Midwest ISO's short-run economic dispatch. These adverse effects were the potential for differential sub-regional usage charges to raise the cost of meeting load within the Midwest ISO footprint by reducing the efficiency of the Midwest ISO's economic dispatch, and the potential for the regional charge on exports, in combination with the injection charge on Midwest ISO generation, to reduce the level of Midwest ISO generation exports below the efficient level and raise the cost of meeting load outside the Midwest ISO.

The potential adverse impact of sub-regional usage charges on the economic efficiency of the Midwest ISO's economic dispatch would be avoided under a highway/byway approach because, by design, there would be no sub-regional usage charges. It appears that the adverse effect on exports, however, would be essentially the same under the highway/byway and injection/withdrawal methodologies. This similarity occurs because the regional export charge under the highway/byway approach would be approximately equal to the sum of the regional export and regional and sub regional injection charges under the injection/withdrawal methodology, assuming that the same total transmission revenue requirement would be recovered in regional per megawatt hour charges under either method. The highway/byway cost allocation methodology therefore would have the same effect of raising the cost of power exported from the Midwest ISO relative to the cost of power generated externally to the Midwest ISO in order to meet load external to the Midwest ISO.

Generation Exit and Entry Effects

The original injection/withdrawal transmission cost allocation methodology had five potential adverse effects on generation exit and entry. First, generation access charges could reduce the amount of capacity available to meet Midwest ISO load if Module E is not effective in requiring load serving entities to contract for sufficient generation. Second, the application of injection and withdrawal charges to the gross injections and withdrawals of energy storage resources would adversely impact their economics, reducing investment in such resources and potentially causing existing storage resources to cease operation. Third, differences in the level of the local access charges levied on generation in different local pricing zones would affect the cost of providing capacity across local pricing zones and potentially lead to inefficiencies in generator location with the Midwest ISO. Fourth, the lack of a direct relationship between the access charge and the transmission costs incurred to serve remote generation could lead to inefficient patterns of generation and transmission investment. Fifth, access charges applied to nominal generator capacity could have differential effects on the private (as opposed to social) cost of high versus low availability generation, leading to inefficient investment choices.

The highway/byway design would avoid the potential adverse impacts associated with the first, third and fifth issues because there would be no access charges applied to generation.

Since the regional per megawatt hour transmission usage charge collected on gross withdrawals under a highway/byway methodology would be roughly equal to the sum of the load and generation regional per megawatt hour transmission usage charges under the original injection/withdrawal methodology, the highway/byway methodology would have essentially the same adverse impacts on the economics of energy storage resources that we identified for the injection/withdrawal methodology. While there would be no regional transmission usage charge on generator injections under the highway/byway methodology, the usage charge on withdrawals would be correspondingly higher, so the impact of the highway/byway methodology on the economics of energy storage resources such as pumped storage would be essentially the same as the negative impact identified in our original report with respect to the injection/withdrawal methodology

This is illustrated in Table 10, which shows the effect of a $4 per megawatt hour usage charge on power withdrawals on the economics of a pumped storage resource. It can be seen by comparing Table 10 with Table 7 in the March 5th report that the effect of a $4 per megawatt hour usage charge under a highway/byway methodology is almost identical to the combined effects of a $2 per megawatt hour usage charge on generator injections and a $2 per megawatt hour usage charge on power withdrawals under the injection/withdrawal methodology.

Table 10
Impact of Highway/Byway Usage Charges on Energy Storage Economics

	Base Case	**No Price Impacts**	**Uniform Price Reductions**	**Off-Peak Price Reductions**
		charge on gross withdrawals and injections		
On-Peak Price	$30	$30	$22	$30
Off-Peak Price	$20	$20	$12	$12
Variable O&M	$2	$2	$2	$2
Transmission Charges	$0	$4	$4	$4
Private Margin	$5.0	$1.0	$1.80	$9.00
Social Margin	$5.0	$5.0	$5.80	$13
		charge on net withdrawals only		
On-Peak Price	$30	$30	$22	$30
Off-Peak Price	$20	$20	$12	$12
Variable O&M	$2	$2	$2	$2
Transmission Charges	$0	0.4	0.4	0.4
Private Margin	$5.0	$4.60	$5.40	$12.60
Social Margin	$5.0	$5	$6	$13

As we suggested in our discussion of this feature of the injection/withdrawal methodology, this undesirable outcome of applying highway/byway usage charges to energy storage resources could be avoided by applying the transmission usage charge only to the net energy withdrawals over a time frame long enough that the net withdrawals reflect the losses associated with the operation of the storage resource.

The fourth market inefficiency related to generator exit and entry that was identified as potentially associated with the injection/withdrawal methodology was for the socialized investment process to accommodate the construction of transmission to serve generation that would not be economic if the generator owner had to evaluate the economics of the combined generation and transmission costs in making its investment decision (as would be the case if the generator not only had to pay for the direct interconnection costs but also had to contract for any transmission expansions intended to reduce congestion when the generator is operating). We observed that it was difficult to assess the magnitude of these potential distortions because some of the transmission investments at issue may be intended to subsidize the development of wind generation in the absence of carbon taxes. In addition, the magnitude of these distortions could perhaps be limited through the application of appropriate relative cost benefit analyses in the development of the Midwest ISO Transmission Expansion Plans.

The application of the highway/byway methodology might somewhat exacerbate this adverse effect as under the highway/byway methodology no local transmission costs would be imposed on generators, so that generators would not need to recover any local 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 material relative to the injection/withdrawal methodology, given the potentially very limited and indirect relationship between the access charges collected under the injection/withdrawal methodology from the generators served by a particular transmission expansion and the costs of that transmission expansion. Hence, the relative merits of the highway/byway and injection/withdrawal methodology depend largely on the extent to which the proposed rules for allocating transmission costs to zones and between loads and generators achieve a rough justice in attributing these costs to those who cause and benefit from the transmission expansion, which is an empirical question which we have not attempted to address.

Power Consumer Location and Consumption Impacts

We identified the original injection/withdrawal methodology as having two potential adverse market impacts relating to consumers. The first was that differences in the level of the local per megawatt withdrawal charges across pricing zones could adversely effect the economics of power intensive consumer location decisions to the extent that the decrease in power costs resulting from the transmission investments was not commensurate with the increase in the local transmission charge. We anticipate that the magnitude of these local charges on power consumers within the zone would be somewhat higher under the highway/byway methodology than under the injection/withdrawal methodology in zones with substantial generation capacity serving load external to the zone (holding constant the division of transmission costs between the local and regional level under the two allocation methodologies as we assumed above).[38] Conversely, the total local access charges borne by power consumers (including those incurred through capacity or renewable energy contracts with remote generation) would be lower under the highway/byway approach than under the injection/withdrawal approach for power consumers in zones whose load was met in substantial part by generation external to the zone.

Whether the increases and decreases in transmission charges on local consumers at various locations under the highway/byway approach would lead to any reduction in market efficiency cannot be answered in the abstract as it depends on the benefits provided by the transmission investments whose costs are recovered in these transmission access charges. If a large power consumer would realize a reduction in annual power costs of $11,000 per megawatt of its average monthly peak load from a transmission investment, offset partially by a $3,000 per megawatt increase in transmission charges to

[38] This likelihood can be illustrated with a simple example. Suppose that the peak load in a zone were 1000 megawatts, and that the average of the monthly peaks was 800 megawatts. Then suppose that there were 1150 megawatts of generation within the zone to serve the local load and an additional 1150 megawatts of generation serving external load. The local load would bear 800/3100 of the local access charges directly, and 1950/3100 of the charges in total, including the charges on local generation used to serve the local load. Under the highway/byway approach, all of the local access charge would be borne by the local load, so it would be about 50% higher overall than under the injection/withdrawal methodology.

fund that investment, the net effect would not be to cause the power consumer to relocate. Indeed, if offered the opportunity to contract for such a transmission investment that would reduce its power costs by this amount, the power consumer would presumably willingly do so.

However, if the power market benefits to the power consumer from that transmission investment were only $1,000 per megawatt of average monthly peak load and it had to bear $3,000 of additional transmission charges per megawatt of average monthly peak load, then the higher access charges under the highway/byway methodology could contribute to inefficient shifts in the location of power intensive industrial consumers.

The second potential adverse impact on market efficiency relating to power consumers under the injection/withdrawal methodology would be an incentive of load serving entities located in pricing zones with multiple load serving entities to incur inefficiently large costs to reduce their monthly peak loads in response to the increase in local transmission access charges under the highway/byway approach.[39] This potential adverse impact would be somewhat greater under the highway/byway methodology than under the injection/withdrawal methodology in zones in which there is substantial generation serving loads in other zones as more access charges would be borne by the local load under the highway/byway methodology for the reasons discussed and illustrated above.

Forward Contracting and Retail Procurement Processes

We concluded that the original injection/withdrawal methodology was likely to have adverse effects on the ability of both suppliers and consumers to utilize standard industry forward financial contracts to hedge their power market risk. This adverse effect was likely because the cost of covering such contracts either with physical generation or spot purchases would be impacted by the regional transmission usage charge collected from generators. We foresaw a potential for both the level of the transmission charges to be

39 It would be efficient for the power consumers to incur costs to reduce their peak loads in order to avoid true social costs associated with serving those peak loads, but incurring costs to avoid the transmission access charge is not efficient because the transmission costs reflected in the access charge are sunk.

recovered and, particularly the regional/local allocation fractions used to allocate these charges between local access charges and regional usage charges to be sufficiently uncertain that this uncertainty would, at the margin, discourage reliance on standard financial forward contracts. While Midwest ISO market participants could negotiate ways to handle these uncertainties in customized contracts, a reduced ability to take advantage of the liquidity provided by standard financial contracts would have been a negative impact of the original injection/withdrawal methodology. These negative market effects would be completely avoided under a highway/byway cost allocation methodology because there would be no regional usage charges paid by generators on their injections.

FTR Allocations

Finally, we noted that it is likely that many or all of the transmission upgrades whose costs would be recovered through the application of the injection/withdrawal methodology would make feasible the award of additional auction revenue rights or long-term transmission rights that absent the introduction of other rules in conjunction with the injection/withdrawal methodology would be allocated in the normal Midwest ISO allocation process. The likely outcome of this process would be that valuable auction revenue rights or long-term transmission rights made feasible by transmission investments whose costs were socialized across the Midwest ISO footprint would be awarded to particular load serving entities at zero cost. Aside from the equity issues associated with such an outcome, we observed that awarding these auction revenue rights and long-term transmission rights through a non-market process increased the net transmission costs that would need to be recovered through access charges and usage charges that potentially distort market decisions and produce the various kinds of market inefficiencies discussed above.

This feature of the injection/withdrawal methodology is also a feature of the highway/byway methodology, but in both cases it does not appear to be inherent in the design and could be avoided by adopting a variety of mechanisms for capturing the value of the congestion rents collected as a result of transmission investments funded through these mechanisms and netting them from the transmission costs recovered through either of these mechanisms.

Addendum B

Market Impacts of the Revised Injection/Withdrawal Transmission Cost Allocation Methodology

This addendum comments on the revised injection/withdrawal transmission cost allocation methodology set forth in the Midwest ISO March 22, 2010 Draft Straw Proposal. This revised cost allocation methodology differs from the methodology evaluated in our March 5th, 2010 report in five ways.[40] First, the sub-regional allocation layer has been eliminated.[41] Second, the regional per megawatt hour usage charge collected from generators and imports has been eliminated and replaced by increased usage charges collected from loads and exports.[42] Third, the regional transmission usage charge collected from loads will be applied to net, rather than gross withdrawals of energy storage resources.[43] Fourth, the engineering analysis will be carried out and the local/regional allocation fractions will be determined several years prior to the time that the transmission charges will be collected.[44] Fifth, the local access charge collected from generators located within the Midwest ISO will also be collected from generation external to the Midwest ISO that is dedicated to serving Midwest ISO load under module E.[45]

These changes in the injection/withdrawal transmission cost allocation design largely address our four primary recommendations regarding modifications needed to avoid adverse market impacts.[46] The elimination of the sub-regional usage charges would eliminate the potential for adverse impacts on the efficiency of the Midwest ISO's

40 ,See Midwest ISO, Transmission Cost Allocation Design, Midwest ISO Straw Proposal Draft, March 22, 2010, (hereafter March 22 Straw Proposal). The March 22 Draft Straw Proposal also clarifies some details relating to the design of the injection/withdrawal methodology in addition to these five design changes. We understand the discussions regarding the structure of the injection/withdrawal transmission cost allocation methodology are continuing and that the March 22 Straw Proposal may continue to evolve.

41 See March 22 Straw Proposal, pp. 4-5.

42 See March 22 Straw Proposal pp. 4-5.

43 See March 22 Straw Proposal p. 15.

44 See March 22 Straw Proposal p. 11.

45 March 22 Straw Proposal p. 16. It is our understanding that such generation will pay the local access charge of the pricing zone in which the load it serves is located.

46 See Scott Harvey and Susan Pope, Evaluation of Midwest ISO Injection/Withdrawal Transmission Cost Allocation Design, March 5, 2010 pp. 67-70.

economic dispatch arising from differences in the sub-regional usage charge. Similarly, the elimination of the regional usage charge collected from generators would eliminate the potential adverse impact of the uncertain future level of these charges on forward contracting through standard financial contracts within the Midwest ISO footprint.

The issues we identified regarding the impact of the regional usage charges on the economics of energy storage resources have been reduced through the proposed changes in the way the usage charge would be applied to such resources. However, the revised design still appears likely to impose usage charges on some gross withdrawals and may have some unintended consequences on the operation as well as economics of energy storage resources. The source of our remaining concern is the element of the proposed design that would calculate the net withdrawals for conventional energy storage resource such as pumped storage on a daily basis and for storage resources providing regulation (Stored Energy Resources) on an hourly basis.

It is our understanding that pumped storage resources often pump during the weekend in order to fill their reservoir for the coming week, and during high demand periods cannot pump enough to refill their reservoirs overnight during the week. Hence it would not be remarkable for a pumped storage resource to have large net withdrawals of power from the transmission system on each weekend day and then large net injections on several or all weekdays during the following week. If the transmission usage charge were applied to net injections calculated over a period as short as a day, this would effectively apply the usage charge when the operator fills the reservoir over the weekend and might tax a material proportion of the net withdrawals on a gross basis.

The bulk of this potential adverse and unintended consequence could be avoided by calculating the net injections over a period of a week or month.[47] Ideally, even if payments were made weekly or monthly there could be a true up over a longer period so that if a week with large net injections (because of cool weather in which storage was

[47] We understand that more recent formulations of the injection/withdrawal methodology propose calculating net injections over a period of a month; see Midwest ISO, "Overview of Business Rules," RECB Task Force April 9, 2010, p.21.

refilled but not drawn down) were followed by a week with net withdrawals, the charges would be trued up to collect the transmission usage charge only on the net withdrawals over the longer period.[48]

We have a similar concern that while an hourly true up for regulating units will often be appropriate, depending on the design and operation of the regulating resource it is not clear that it will always be long enough for the injections and withdrawals to average out to the level of losses, so it could also apply charges to quantities that are well in excess of the net withdrawals calculated over a longer period of time.

Finally, the Midwest ISO's March 22 Straw Proposal does not address how FTRs made feasible by transmission investments funded in whole or in part through the Injection/Withdrawal charges will be accounted for. The Midwest ISO has indicated that they are in the process of developing this methodology and we agree that as long as the intent is to establish a mechanism to recover the value of these FTRs (or the associated congestion rents) and net them from the transmission costs recovered through the various injection/withdrawal access and usage charges, there is time to work out the details.

In addition to these four problem areas with the injection/withdrawal methodology that we highlighted in our recommendations, our report noted a number of other potential adverse market impacts whose significance or materiality was less clear.

These other effects included the effect of the various usage charges on the economic efficiency of the level of exports, the effect of access charges on the economics of generation investment generally and the effect of differential local access charges in particular on generation location decisions, the effect of uneconomic subsidized transmission investments on generation location decisions, the differential effect of generation access charges on high and low availability factor generation, and the effect of load access charges both on the location and exit decisions of energy intensive consumers

48 The longer the period over which a true up is applied, however, the greater will be the need for rules to prevent behind the meter generation and load from being treated as a pumped storage facility.

and on peak load. Our assessment of the potential market impacts of these various features of the injection/withdrawal design is not materially changed by the changes embodied in the March 22, 2010 Straw Proposal. The adoption of a rolling determination of regional and local allocation fractions may slightly assuage some of the generation exit and entry concerns by providing more short-run visibility regarding the likely level of these access charges.

Addendum C

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; Northwest RTO; Ontario IMO/IESO; PowerEdge; PJM; PJM Supporting Companies; PP&L; Progress Energy; Public Service Electric & Gas; 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; Tucson Electric Power; Westbrook Power; Williams Energy Group; and Wisconsin Electric Power Company.