Synapse
Energy Economics, Inc.

The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region

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Executive Summary

Wind as an electricity supply resource has been getting steadily cheaper, and its technical performance characteristics continue to improve as larger turbine sizes and higher hub heights capture both economies of scale and more of the passing wind.[1] Simultaneously, the projected cost of coal-fired power has begun to climb; the increasingly global coal market has given rise to higher coal prices, and many existing coal plants will need to be retired or retrofitted with new environmental controls to comply with stricter regulations being enacted by the Environmental Protection Agency (EPA).

These trends in electricity supply costs are particularly relevant in the Midwest ISO (MISO) market area. Today, more than half of the MISO generating capacity consists of coal-fired units. MISO also contains effectively inexhaustible supplies of the most economic wind power available to the nation. Over the past five to ten years, this low-cost energy resource has begun to be tapped in ever-increasing quantities. As of December 2011, wind installed in the MISO region had risen to 10 gigawatts (GW). However, the inadequate capacity of many segments of MISO's transmission grid, coupled with the inflexibility[2] of much of the baseload incumbent generation has given rise to operational complexities and system constraints. This leads to costly congestion and uneconomic curtailment, or spilling, of available wind. To relieve the bottlenecks and capture the economic and environmental benefits of more electricity from wind, investments need to be made in the region's transmission system.[3]

The MISO region recently developed a new type of transmission project, labeled Multi-Value Projects (MVPs), to address reliability, economic, and policy needs. Among other things, these projects address congestion on the transmission system, reliability constraints, and clean energy mandates. According to MISO, the 17 approved Multi-Value Projects (collectively, the MVP portfolio) will provide economic benefits exceeding their costs, and will enable the delivery of at least an additional 41 million megawatt-hours (MWh) of wind energy per year—enough to satisfy Renewable Portfolio Standard mandates in MISO states.

Additional Investments May Benefit Ratepayers

While the MVP portfolio serves as a starting point for bolstering the MISO transmission grid, additional wind-enabling transmission investments may also provide significant benefits to consumers in the region. In this study, Synapse examines two related questions: 1) How would electric market prices in MISO be affected by the addition of new wind supply—above and beyond

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[1] Bolinger, Mark and Ryan Wiser, Lawrence Berkeley National Laboratory, "Understanding Trends in Wind Turbine Prices Over the Past Decade," October 2011. Report LBNL-5119E. See Section 3.4, page 12-15. Also see Wiser, Ryan, Eric Lantz, Mark Bolinger and Maureen Hand, "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects," February 2012. Available at http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf.

[2] Inflexibility refers to a relatively limited ability of some generation resources to ramp up and down quickly, or to start and stop quickly, as may be needed to balance load and supply on a system with more variable output generation (e.g., wind).

[3] In addition to expanding the transmission system, prerequisites for capturing additional wind benefits include: 1) flexible generation (and demand) resources to balance load with supply; and 2) highly coordinated operation across regions and use of the best possible forecasting tools by power system controllers.

what would be enabled by the MVP portfolio? And 2) How would retail electric rates in MISO be affected by additional transmission investments—above and beyond the MVP portfolio? Looking at these two effects, together, provides a sense of how beneficial it might be to invest in additional wind-enabling transmission in MISO.

Synapse's study consists of two major components. First, we examine the downward pressure on energy market prices associated with adding more wind power to the MISO grid.[4] Using a spreadsheet model developed by Synapse, we calculate the supply-induced price effect (SIPE) that would serve to depress MISO energy market prices through the addition of wind supply to the grid. Sensitivity analyses for this model were run across different coal plant retirement scenarios, and different levels of wind installation.

Second, we examine the retail rate impacts associated with existing and future transmission in MISO. The study evaluates the rate impact of existing transmission in MISO as a whole and for one specific utility, evaluates the expected rate impact of the MVP portfolio, and estimates the rate impact associated with three scenarios for transmission expansion above-and-beyond the MVP projects. These scenarios—which are rough benchmarks for the cost of needed transmission – are based in part on the "indicative transmission" portfolios reported on in MISO's Regional Generation Outlet Study, and represent low, medium, and high transmission expansion scenarios for the MISO region. They are also based in part on more aggregate assessments of required transmission resource cost for the MISO area conducted through the stakeholder-guided Eastern Interconnection Planning Collaborative (EIPC). These scenarios represent a proxy for the cost of transmission needed to increase the scale of wind generation connected to the grid.

It is important to note that this study does not directly address the question of "how much" transmission will be necessary to deliver given quantities of additional wind power by a given year. This is a planning exercise that we did not undertake, which would depend in large part on the load and supply resource mix and locations assumed.

We note that, with good system planning, it is likely that large quantities of wind could be integrated with low or moderate transmission investments – though still larger increases than have been seen in the recent past. For example, to the extent that load growth can be kept to a minimum through demand response and energy efficiency, incremental transmission need to integrate wind is lowered (relative to a baseline with greater load growth) because a key determinant of transmission need is peak load level. Transmission projects would still be required to connect remote wind resources to the grid, and "backbone" investments will still be needed across key areas of the Midwest. But unending investment cycles of extra-high voltage lines should not be necessary, and the cumulative rate impacts should remain small. Transformation of the supply fleet to much more flexible operation (e.g., by adding gas plants that can ramp up and down quickly), and the presence of extensive coordination, control, and forecasting improvements in the electric power sector could also mitigate the need for dramatically expansive levels of transmission. Lastly, it will be important that both existing and newly-freed-up "headroom" on the transmission grid is fully exploited.

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[4] The Midwest ISO Market Monitor (Potomac Economics) recognizes and acknowledges these downward price pressures. See the 2010 State of Market Report, page 7.

While this study does not perform the planning exercise described above, it does allow for an evaluation of the overall rate impacts of adding new increments of transmission and new increments of wind to the MISO system.

Key Findings

Transmission-Enabled Wind Energy Leads to Reduced Electric Market Prices

Synapse's analysis indicates that the effect of introducing greater levels of wind resources into MISO is to generally depress the average annual market price, relative to a baseline case of no additional wind generation beyond the existing 10 GW in place in MISO today. Since wind energy "fuel" is free, once built, wind power plants displace fossil-fueled generation and lower the price of marginal supply—thus lowering the energy market clearing price.

Figure ES-1, below, illustrates the energy market price trends that arise out of Synapse's modeling exercise. This graph illustrates our modeled level of energy price declines in the Midwest over the coming decades, if wind (and new transmission, as estimated in Table ES-2, below) comes online in the quantities estimated. For each of the coal retirement sensitivity cases shown in Figure ES-1 (i.e., 3 GW, 12 GW, and 23 GW), market prices are reduced significantly as more wind is added to the system.

For example, as seen in the 3 GW coal retirement sensitivity case (the dotted line in Figure ES-1, below), the market price reduction in 2020 associated with a 20 GW addition to the wind resource base (i.e., total wind increases from 10 GW to 30 GW) is roughly $14/MWh, and a 40 GW wind addition leads to an average energy price decline of more than $21/MWh.[5]

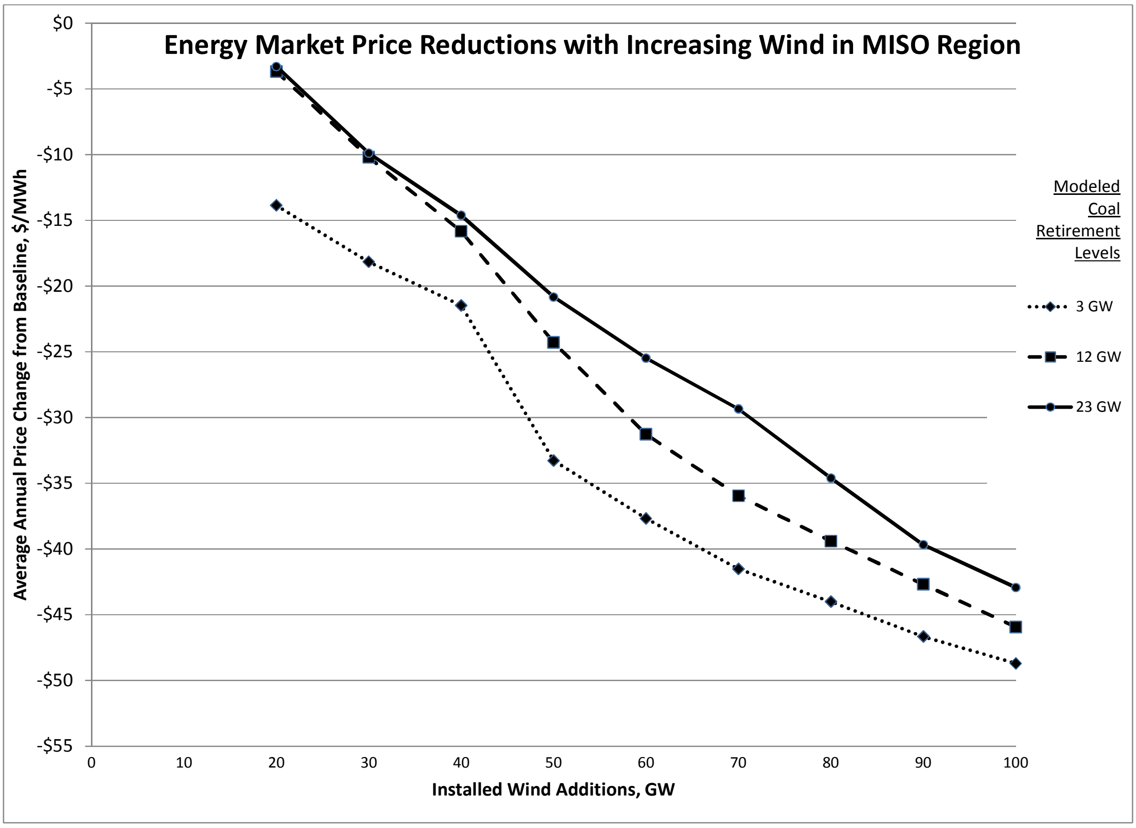
These market price declines will lead to reduced overall energy costs. For this coal retirement sensitivity, power supply costs for MISO-region customers could range from $3.9 billion to $7.9 billion per year lower than baseline costs for the 20 GW wind addition, and from $6.1 to $12.2 billion per year lower than baseline costs for the 40 GW addition.[6] These cost savings will exceed the annual costs of transmission improvements needed to integrate this level of wind addition. When including the effects of transmission, the net savings ranges from $3.0 billion to $6.9 billion per year for the 20 GW wind addition scenario, and $3.3 to $9.4 billion per year for the 40 GW wind addition scenario.

For an average MISO region residential customer using 1,000 kWh per month, this translates to a net savings that would range from $63 to $147 per year in 2020 (for the 20 GW wind addition scenario), and from $71 to $200 per year for the 40 GW wind addition scenario.

5 Electric energy price movements in a market such as MISO's are composed of many complex factors, and our model is a simplified representation of the system. While it captures the broad trends that can be expected, there is additional analytical work required to more carefully optimize the resource expansion that would be expected if or as the Midwest region moves towards the installation of tens of thousands of MW of additional wind resources.

6 The lower value reflects a future year assumption that MISO market price is a proxy for supply costs for 50% of regional power supply, and the upper value assumes that the market price is a full (100%) proxy for the costs to load.

Figure ES-1. MISO Market Energy Price Decreases from Increased Wind – Supply Curve Effect



Synapse's analysis suggests that ongoing wind installations across the MISO grid will continually and inexorably exert downward price pressure on market energy prices. Energy market price reductions will be material and pervasive, ranging initially (2012 – 2018) from $3 to $10/MWh, and continuing to reduce energy market prices by $10 to $49/MWh by 2031, when on the order of 100 GW of wind energy could be online in the Midwest region.

Rough temporal patterns emerging from Synapse's analysis suggest that the supply-induced price effect from wind additions would be greatest in spring, fall, and winter, when aggregate wind plant output is expected to be highest.

Transmission Expansion Has a Small Effect on Retail Rates

Synapse's analysis shows that adding wind-enabling increments of transmission above-and-beyond the MVP portfolio would have a small effect on the average electricity bill in MISO. Table ES-1, below, shows the transmission rate impact associated with each of the studied scenarios for the years 2015, 2021, and 2031. These transmission expansion scenarios could allow for up to 100 GW of additional wind energy in MISO.[7] As shown below:

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[7] As we have noted elsewhere, our analysis did not attempt any form of bottom-up estimate of total transmission need for any given amount of wind. The actual total amount of transmission needed to interconnect 100 GW of additional wind in MISO by 2030 or thereabouts is unknown. We do note that the current Phase II portion of the

- At the low end of the range, the rate impact of the MVP portfolio in 2015 is $1.0/MWh (0.10 cents/kWh).
- At the high end of the range, the rate impact of the MVP portfolio plus Synapse's High T Expansion scenario in 2031 is $11.2/MWh (1.12 cents/kWh).

Table ES-1. Incremental Rate Impacts of Different Transmission Build-Out Scenarios in the Midwest

Transmission Scenario - Cost Basis	Total Cost of New MISO Transmission "for Wind", $ Billions	Transmission Rate Impact of Scenario Listed, for Year Listed, $/MWh		
		2015	2021	2031
Current MVP Only	$5.2 B	$1.02	$1.64	$1.28
Current MVP + Synapse Low T Expansion	$24.2 B	$1.02	$4.85	$6.52
Current MVP + Synapse Medium T Expansion	$31.2 B	$1.69	$5.93	$8.46
Current MVP + Synapse High T Expansion	$40.2 B	$1.76	$6.40	$11.20

Table ES-1 shows that transmission rate impacts in the near-term are modest, adding a few dollars per megawatt-hour (MWh) to retail electricity bills.[8] For perspective, total retail power rates currently average $87/MWh in the MISO region. The largest component of that rate is energy supply costs.

Incremental Transmission Costs to Enable New Wind Will Be More than Offset by Energy Market Price Reductions

The energy market price effects shown in Figure ES-1 significantly offset—and often exceed—the rate effect associated with expanding the transmission system. Table ES-2, below, lists the *total* average transmission rate associated with each scenario for the years 2015, 2021, and 2031. This total rate includes all transmission rate cost components, including costs for existing transmission and expected MISO reliability projects. The table also shows the approximate range of wind capacity (in gigawatts) enabled by each transmission scenario, and the approximate range of market price *reduction* resulting from the wind enabled by each transmission scenario.

Table ES-2 below indicates that the price savings associated with the wind additions modeled by Synapse exceed not only the incremental rate effect of the transmission expansion scenarios (shown in Table ES-1), but also, in many cases, the *total* transmission rate associated with each scenario.

Eastern Interconnection Planning Collaborative process will estimate this level for EIPC "Scenario 1", which includes MISO wind increments on the order of 100 GW by 2030, and high levels of coal plant retirement.

[8] We have relied upon the MISO methodology for determining transmission revenue requirements and associated retail rate impact for transmission addition.

Table ES-2. Total Average Transmission Rates Including Build-Out Scenarios in the Midwest

Transmission Scenario - Cost Basis	Approximate Range of MISO Region Wind Enabled by Scenario, GW	Total Average Transmission Rate, $/MWh			Range of Energy Price Reduction from SIPE Model, $/MWh
		2015	2021	2031	
Current MVP Only	20-30	7.8	8.1	5.8	3-10
Current MVP + Synapse Low T Expansion	30-50	7.8	11.4	11.1	10-33
Current MVP + Synapse Medium T Expansion	>50	8.5	12.4	13.0	>21
Current MVP + Synapse High T Expansion	>70	8.6	12.9	15.8	> 29

In sum, this study suggests that adding more wind power to the grid in MISO, above and beyond what will be enabled by the MVP portfolio, would result in the continual decline of energy market prices and lead to lower electric rates for ratepayers (relative to rates in a less windy electrical landscape)—even when you factor in the costs of additional transmission.[9]

In sum, this study suggests that adding more wind power to the grid in MISO, above and beyond what will be enabled by the MVP portfolio, would result in the continual decline of energy market prices and lead to lower electric rates for ratepayers (relative to rates in a less windy electrical landscape)—even when you factor in the costs of additional transmission.

Moreover, the price suppression effect seen in our analysis would be even greater if gas prices rise above the Energy Information Administration's current Annual Energy Outlook real price projections for 2020 and 2030. Similarly, the effect would be magnified under scenarios with large coal retirement, since gas-fired generation would likely be on the margin for a greater share of market-price-setting intervals.

The results of this study cannot precisely discern the extent to which MISO market-wide price depression arising from increased use of wind resources will directly "flow through" to load-serving entities in the region in 2020 or 2030—especially given the significant changes in resource base expected to be in place in those out years. However, it is reasonable to assume that much of the price effect patterns seen here would be reflected in energy costs borne by ratepayers in the MISO region.

While this study does not address the question of "how much" transmission will be needed to deliver additional wind in MISO, we can assume the following: To the extent load growth is reduced by demand-side resource delivery, supply-side resource flexibility increases —and improvements are seen in electric power sector coordination, control, and forecasting—relatively less transmission investment is likely to be required to achieve the wind additions and associated benefits seen in this study, compared to a "business as usual" case that does not see these gains.

[9] While much attention is given to new transmission required for wind, transmission companies and planning entities have always planned for, analyzed, proposed, and built new transmission across the region. Like all transmission, it is part of a complex electrical network and supports delivery of energy independent of its source, providing both reliability and economic benefits.

1. Background

This chapter describes broadly the Midwest ISO (MISO) region and market structure, and the electric power cost components analyzed in this study.

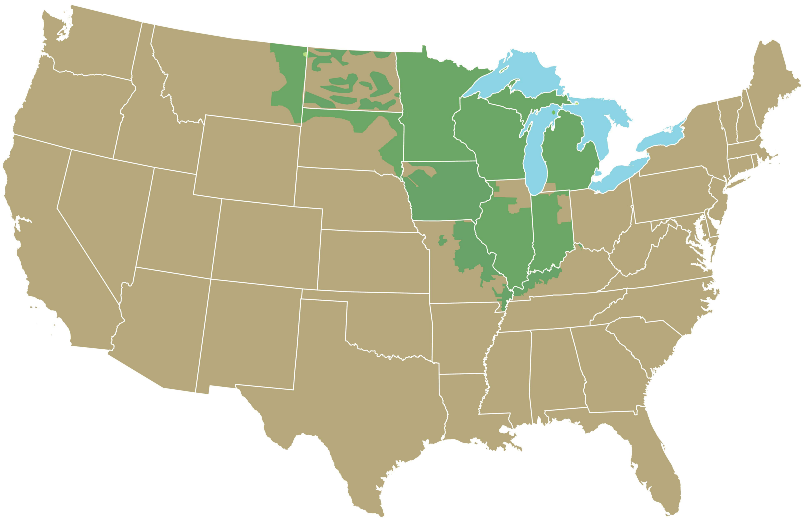
A. Electric Power Market Structure in the Midwest / MISO Market Area

The electric power market structure in the upper Midwest region of the US is composed of a combination of traditional vertically-integrated utility transactions, bilateral supply arrangements between parties, and use of the structured energy markets of the Midwest ISO (MISO).

MISO is an independent and non-profit Regional Transmission Organization (RTO) with a scope of operations that includes generation and transmission system facilities in 11 states[10] and one Canadian province (Manitoba). It has two sets of boundaries: one, referred to as its "market area," which encompasses the utility service territories of entities who are full participants in MISO's energy and ancillary service markets and adhere to its resource adequacy construct; and the other, broader region (referred to as its "reliability area") that also encompasses adjacent entities who use MISO as their North American Electric Reliability Corporation (NERC) reliability coordinator.

Figure 1 below shows MISO's "market area." As of January 2012, the MISO market characteristics include roughly 131,000 MW (or 131 gigawatts) of generation capacity, serving a peak load of roughly 100 gigawatts (GW).[11] All power that flows on the MISO-controlled grid is subject to MISO's transmission tariff protocols, including its locational pricing construct for energy.

Figure 1. Midwest ISO "Market Area"



Source: Midwest ISO Fact Sheet, available at https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=21100.

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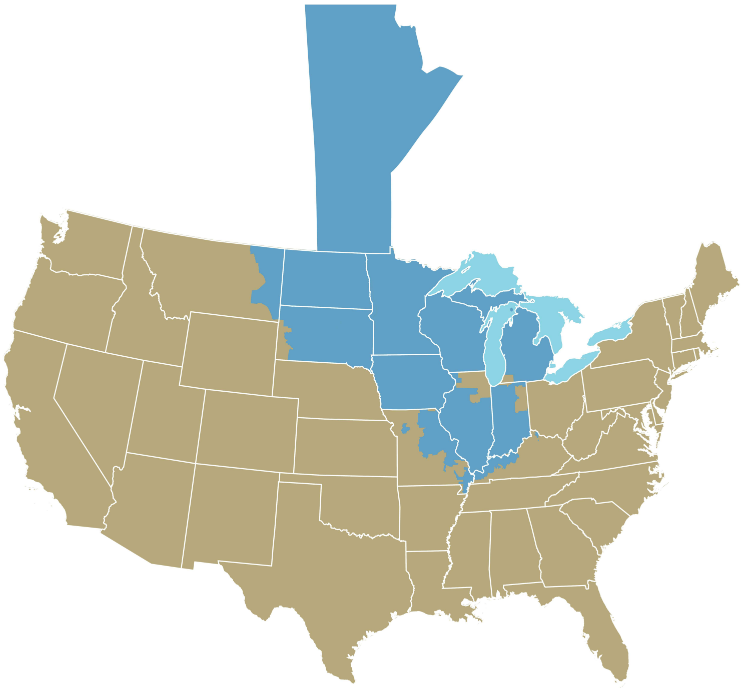
[10] Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, North and South Dakota, Montana, Missouri, and Kentucky.

[11] MISO has recently seen additional entities join, and the loss of major eastern region entities First Energy and Duke Energy Ohio and Duke Energy Kentucky. MISO's projected peak load for 2012 for its market area is roughly 93,000 MW.

Figure 2 depicts the expanded “reliability area” boundary of MISO, representing the full scope of reach of MISO’s reliability coordination responsibilities.[12] Primarily, this reliability area includes the rest of the legacy Mid-Continent Area Power Pool (MAPP) area, including both its US regions (primarily North and South Dakota utilities whose service territories don’t already participate in the MISO market region) and Manitoba.

Figure 2. Midwest ISO “Reliability Area”



Source: Midwest ISO Fact Sheet, available at https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=21100.

The MISO region is interconnected with wind-rich regions to its south, in Nebraska and the Southwest Power Pool area[13], and in the PJM region to its east. The PJM region’s significant wind resources are concentrated in its western portions, in Illinois, Indiana, Ohio, West Virginia, and western Pennsylvania. For the purposes of the analyses contained in this report, we focus on activities within the MISO region, but recognize the important synergies associated with its interconnected neighboring regions.

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[12] Reliability coordination responsibilities include administration of the transmission tariff and responsibility for adherence to NERC reliability standards.

[13] The Southwest Power Pool region includes utility service territories in Kansas, Missouri, Oklahoma, Arkansas, Texas, and Louisiana. Nebraska public power utilities are also participants in the Southwest Power Pool, which has multiple levels of participation (see “SPP Footprints” for a comprehensive description of these levels, available at http://www.spp.org/publications/SPP_Footprints.pdf).

B. Electric Power Cost Components

The major elements of electric power costs to serve net load[14] can be categorized into three areas: supply, transmission, and distribution. This report is focused on the two former components, supply and transmission.

Supply Resources: Capacity, Energy, and Ancillary Services

Supply costs reflect generation capacity (i.e., the capability to generate energy) and associated energy production. Supply costs also include the majority of ancillary services required to maintain electric delivery reliability. These services are broadly inclusive of “operating reserves,” or generation capacity utilized: 1) to balance the system, 2) to provide “headroom” to account for contingencies in the supply or delivery systems, such as forced outages of transmission or generation equipment, and, 3) to be available during maintenance outages for generation or transmission systems.

In the MISO region, each of these three components of supply (energy, capacity, and ancillary services) is provided by utilities, operating within the structure of the MISO region tariff. MISO’s spot energy market complements any bilateral procurements or self-supply of energy, and serves as the vehicle through which all energy is dispatched in the MISO region. MISO has functioning ancillary service markets, and has a capacity obligation requirement for all MISO load. MISO also runs a voluntary capacity market auction, which serves primarily to balance the capacity needs of utilities, as most capacity is secured on a bilateral basis.

Delivery: Transmission and Distribution

Transmission and distribution costs in aggregate are sometimes described as “wires charges,” reflecting the means by which electricity is delivered from generation to load. Transmission and distribution costs are made up of more than just wires, as a myriad of equipment and support services are required to successfully, reliably, and economically deliver electricity to homes, institutions, and businesses.

We address MISO region transmission costs in the next section.

Traditionally, distribution charges include all “downstream” retail activities and are regulated by state utility commissions. Transmission charges are regulated by the Federal Energy Regulatory Commission (FERC).

Utilities often collect additional revenues at the retail level to cover costs associated with different regulatory policies or practices in each state. Often these costs are collected as part of the overall revenue requirements for the distribution system. For example, recovery of utility energy efficiency program costs, transitional costs for capacity in “deregulated” states, and state taxes are included on utility bills, sometimes as part of distribution components of a bill, and sometimes as a separate line item.

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[14] Net load refers to load served by power supplies over the transmission and distribution system. Gross load would include load that is served by “behind the meter” generation, including photovoltaic and combined heat and power resources.

2. Cost of Transmission in Midwest Electric Power Markets

In this chapter, we examine the retail rate impacts associated with existing and future transmission in MISO. We begin this analysis by examining the structure for transmission cost recovery within MISO, and investigating how large of an impact transmission costs have on retail electric rates and average electricity bills. In addition to exploring the MISO-level impacts of transmission costs, we examine one Michigan utility, Consumers Energy, and the detailed state-level tariff in place to recover required transmission costs.

Next, we examine "generic transmission costs," such as those used in the recent Eastern Interconnection Planning Collaborative (EIPC) process, and gauge the extent to which these costs can serve to represent the cost of transmission needed in MISO to help deliver more wind to the grid. We do so by comparing the generic EIPC costs to detailed cost information about new transmission facilities under consideration by MISO.

We then examine MISO's analysis of the retail rate impacts associated with the Multi-Value Projects (MVP) portfolio, and determine the retail rate impacts for three transmission expansion scenarios above-and-beyond the MVP projects. This is followed by a discussion of transmission congestion costs.

A. Existing Transmission Costs

Existing transmission costs in the Midwest region are recovered by utilities through regulated tariff structures under the oversight of different state utility regulatory commissions. Generally, the cost of transmission is allocated to retail customer sectors in proportion to the peak load of each sector. The peak load value used could be determined in a number of ways; for example, it could be based on a prior year's peak value, or on the average of peak values seen in each of the prior 12 months of the year.[15] Detailed rate design mechanisms are then used, at the state level, to further allocate each sector's share of transmission costs to the individual customers. For example, if the peak load of a utility is 3,000 MW and the residential sector peak load is 1,000 MW, then residential customers are allocated one-third of the total transmission costs, usually through a relatively simple formulation that spreads the costs over all energy consumption (kWh) of that sector.

Midwest ISO Region

The Midwest ISO (MISO) coordinates the provision of transmission service through its Open Access Transmission Tariff (OATT). The OATT structure is in place to ensure non-discriminatory provision and pricing of transmission service. A utility cannot charge different amounts for transmission to different customers for the same level and quantity of service.[16] The pricing structure of the OATT thus serves as one means to determine the cost of transmission that will

[15] Since many customers, especially smaller customers in the residential and small C&I sectors, do not have demand meters, and thus peak consumption cannot be directly measured, various means are used to estimate the peak load allocated to those sectors.

[16] This is pursuant to the original aims of Open Access Transmission Tariff formulation under FERC Orders 888 and 889 (circa 1996).

eventually apply to all MISO customers, though those costs will be "translated" through state-level ratemaking processes to eventually be applied to individual customers.

Another means to determine transmission costs involves a review of all state-level tariff structures and compilation of their rates to end-use customers. (See, for example, our summary analysis of the retail costs of electricity supply for a residential customer of Consumers Energy. This is provided in the next section).

The bulk of transmission costs in the MISO region vary across utilities. Table 1 (below) lists the current network transmission rates from Schedule 9 of the OATT. Schedule 9 is the "network integration" schedule of the tariff. It serves as a useful point of comparison of transmission rates across utilities, and as a means to estimate the average per MWh or per kWh cost of transmission for customers within each utility.

As seen in Table 1, average per unit costs in 2011 range from a few dollars per MWh[17] to as much as $16/MWh, based on MISO postings and an estimate of utility load factors.[18] These costs cover the base transmission assets currently in place at the utilities across MISO. They do not include the costs associated with future transmission expansion, such as the MVP portfolio, nor do they include the costs of other services provided through MISO and required for delivery of energy, such as ancillary services and the costs for MISO to schedule and dispatch the transmission system.[19] Those costs also flow through to retail customers and are often allocated in similar ways as the cost of transmission itself.

[17] $10/MWh is equal to 1 cent/kWh.

[18] We estimate utility load factors for the purpose of determining average per MWh transmission rates. We use MISO data on energy consumption (from Schedule 26a of its tariff posting) and peak load by utility (from the MTEP 2011 report).

[19] The MISO website lists the entire set of services for which its OATT recovers costs from applicable customers. For example, Schedule 1 (dispatch and scheduling), Schedule 2 (reactive support), Schedule 3 (regulating reserve) and schedules 5 and 6 (operating reserves, spinning and supplemental) recover the costs for the core technical operating requirements of the power grid. See https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspxt.

Table 1. 2011 Midwest ISO Network Transmission Rate

MISO ZONE	Transmission Owner Name	2011 Network Transmission Rate, $/MW-year	2011 Network Transmission Rate, $/MW-month	Estimated Annual Load Factor	Equivalent $/MWh Rate at Est. Load Factor
1	ITC Midwest	$83,010	$6,918	0.60	$15.79
2A	ATCLLC Madison G&E	$50,620	$4,218	0.60	$9.63
2B	ATCLLC Wisconsin Public Service	$50,620	$4,218	0.60	$9.63
2C	ATCLLC Wisconsin P&L	$50,620	$4,218	0.60	$9.63
2D	ATCLLC Wisconsin Energy	$50,620	$4,218	0.60	$9.63
2E	ATCLLC UPPC	$50,620	$4,218	0.60	$9.63
3A	Ameren Illinois	$13,765	$1,147	0.55	$2.86
3B	Ameren Missouri	$11,123	$927	0.55	$2.31
5	Cinergy Services (including IMPA & WVPA)	$20,788	$1,732	0.58	$4.09
6	City of Columbia, Missouri	$10,192	$849	0.55	$2.12
7	City Water, Light & Power (Springfield, IL)	$22,397	$1,866	0.55	$4.65
8	Great River Energy	$56,230	$4,686	0.55	$11.67
9	Hoosier Energy	$55,453	$4,621	0.55	$11.51
10	International Transmission Company	$30,345	$2,529	0.57	$6.08
11	Indianapolis Power & Light	$7,982	$665	0.55	$1.66
13	Michigan Joint Zone (METC, MPPA, Wolverine)	$31,096	$2,591	0.58	$6.12
14	Minnesota Power	$30,476	$2,540	0.60	$5.80
15	Montana-Dakota Utilities Co.	$34,321	$2,860	0.60	$6.53
16	NSP Companies	$37,774	$3,148	0.55	$7.84
17	Northern Indiana Public Service Company	$36,630	$3,052	0.60	$6.97
18	Otter Tail Power	$43,039	$3,587	0.55	$8.93
19	Southern Illinois Power Cooperative	$24,212	$2,018	0.55	$5.03
20	Southern Minnesota Municipal Power Agency	$35,662	$2,972	0.55	$7.40
23	Vectren Energy	$28,022	$2,335	0.60	$5.33
24	MidAmerican Energy Company	$15,203	$1,267	0.60	$2.89
25	Muscatine Power and Water	$14,811	$1,234	0.65	$2.60
26	Dairyland Power Cooperative	$45,596	$3,800	0.60	$8.68
27	Big Rivers Electric Corporation	$11,985	$999	0.60	$2.28
	MISO Drive Through Rate	$29,715.8	$2,476.3	0.6	$5.65

Source and notes: 2011 Midwest ISO Open Access Transmission Tariff, Schedule 9, Network Integration rate. Estimated load factor based on peak load by utility, and energy withdrawal amounts from Schedule 26a. Some utilities' load factors estimated due to difficulty in mapping between available peak load data and available energy withdrawal data. Computation of per MWh rate by Synapse based on the listed annual transmission rate and the estimated load factor.

The data reflect differences that arise due to the pattern of transmission additions across the individual service territories. When a transmission project is completed and is added to a utility's rate base, the short-term effect is to see a relative jump in transmission rates, reflecting the economic (and physical) "lumpiness" of transmission.[20] Utilities in the MISO region have added

[20] Lumpiness refers to the fact that transmission additions are generally not made in small, discrete pieces, but rather in a large lump. This lump of investment captures economies of scale of transmission construction and reflects the realities of transmission planning, which requires choosing a long-lived asset to serve a potentially increasing amount of load over its 40+ years of physical life.

differing amounts of transmission in the recent past, and the current rate base (and ensuing rates) will reflect these different paces of transmission addition; the different rates seen across utilities in Table 1 illustrates just that. As we will address in the next section of this report, certain increments of transmission (i.e., the Multi-Value Projects) will see their costs spread across all MISO utilities, resulting in a more even effect on rates across all utilities compared to the "license plate"[21] rate effect seen with individual service territory transmission additions.

In addition to providing the network transmission rates (shown in Table 1), MISO also estimates current average retail transmission costs, at an aggregate level. In Appendix E.3 of the 2011 MISO Transmission Expansion Plan (MTEP 2011), MISO computes an average transmission rate of $6.20/MWh, or 0.62 cents/kWh. It uses data from the EIA's Annual Energy Outlook (April 2011) and its own local balancing authority load shares to determine this value. It is not clear from the report if these costs include only pure transmission, such as is reflected in the OATT values in Table 1 above, or if the data also include ancillary service and related MISO costs to operate the grid. We do note that the MISO "drive through" rate of $5.65/MWH (0.56 cents/kWh), which reflects average costs to use the existing MISO transmission grid, is lower than MISO's Appendix E.3 retail rate estimate, which suggests either that the retail rate estimate includes more than just pure transmission, or is reflective of differences between EIA and MISO data collection methods or parameter use.

Based on MISO's data analysis, transmission costs represent 7.1% of the average electricity bill in the MISO region.[22] Individual state transmission rates vary, and MISO reports, in aggregate, a range of costs between 5.5% and 10.3% of average electricity bills.

Michigan

Most electrical load in Michigan is served by a group of nine separate investor-owned utilities. Together, these utilities sold roughly 96 million MWh in 2010.[23] The remaining Michigan load was served by a number of relatively smaller cooperatives, in total selling 3.3 million MWh in 2010. Consumers Energy made about 35% of electric energy sales in Michigan in 2010, or roughly 35 million MWh. Its peak load was 8,190 MW in 2010.[24]

While load in Michigan is served by several different utilities (as noted above), the bulk of transmission service is provided by one transmission company, ITC Holdings, which operates two subsidiary transmission companies, Michigan Electric Transmission Company (METC) and

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[21] "License plate" rate is the term given to a transmission cost allocation structure that is analogous to motor vehicle license plate differences across states. Each utility's customers are responsible for the costs of transmission within the rate base of their own utility, but they can access the transmission grid across all of MISO without incurring other costs (just as one can generally use the interstate and intra-state highway system across state lines without incurring an additional motor vehicle registration fee from those other states). This is in comparison to "postage stamp" allocation processes that would spread the costs of transmission across all users in MISO – as will be done with the Multi-Value Project portfolio.

[22] See Table E.3-2: Current MISO Retail Rate Component Share, pages 2-3 of Appendix E.3 to the 2011 MISO Transmission Expansion Plan.

[23] Statistical Data of Total Sales, Electric Utilities in Michigan, Year Ended December 31, 2010. Available at http://www.dleg.state.mi.us/mpsc/electric/download/electricdata.pdf, page 1.

[24] Schedule E-4, page 1 of 2, "Maximum Demand MW", Exhibit A-10 (LDW-4) in the rate case, Case No. U-16794 before the Michigan Public Service Commission.

International Transmission Company (ITC). MECT operates in the Consumers Energy service territory, and ITC operates in the Detroit Edison service territory.

To demonstrate the role that transmission costs play in overall electricity bills, we provide a summary analysis of the retail costs of electricity supply for a residential customer of Consumers Energy, including the costs of transmission provided to Consumers Energy's customers from Michigan Electric Transmission Company. The results of this analysis are presented in Table 2.

Table 2. Consumers' Energy Supply, Transmission, and Distribution Costs

Rates, cents/kWh	Customer Monthly kWh Consumption		
	250	500	1000
Fixed Charge	2.4	1.2	0.6
Power Supply	7.3	7.3	7.3
Transmission	0.6	0.6	0.6
Anc Svc / Disp	0.2	0.2	0.2
Total Transmission/AncSvc/Disp	0.8	0.8	0.8
Distribution	3.4	3.4	3.4
Total Rate	13.9	12.7	12.1
Bills, $/Month			
	250	500	1000
Fixed Charge	6.00	6.00	6.00
Power Supply	18.14	36.28	72.57
Transmission	1.53	3.06	6.12
Anc Svc / Disp	0.55	1.09	2.19
Total Transmission/AncSvc/Disp	2.08	4.15	8.31
Distribution	8.62	17.24	34.48
Total	34.84	63.68	121.36
Transmission - Share of Bill	4.4%	4.8%	5.0%

Sources/Notes: Comparison of Monthly Residential Bills for MPSC-Regulated Michigan Electric Utilities, December 1, 2011. Consumers Energy Tariff for Residential service, MISO Schedule 9 transmission tariff. The table reconciles the information available from the MPSC, Consumers Energy, and the Midwest ISO to arrive at a final estimate of the rough breakdown between supply, transmission, and distribution costs for a Consumers Energy residential ratepayer.

As seen in the table above, transmission represents a relatively small share of the total costs for a Consumers Energy customer—ranging from 4.4 to 5.0%. The above table also corresponds roughly with the retail "share of transmission" costs determined by MISO and presented in their MTEP 2011 report appendix.[25] That appendix showed a 4.5% share for transmission as a percentage of retail bills for the RFC-MI EIA Study Region.

B. Generic Costs and Characteristics of New Transmission

Increasing the delivery of renewable energy often, but not always, requires at least some new transmission.[26] Sometimes that new transmission is only what is needed to connect a new

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[25] Appendix E.3 of the 2011 MISO Transmission Expansion Plan, Table E.3-2, page 2.

[26] While the term "new transmission" often connotes new right of way (ROW) and towers and lines, and extensive regulatory delay and disagreement over cost allocation, it is important to remember that there are times when

resource (e.g., wind farm) to the nearest point of interconnection with the regional transmission grid. Other times, such as has been seen in certain areas of the Midwest (e.g., the Buffalo Ridge region of southwestern Minnesota / eastern South Dakota / northwestern Iowa)[27] new "outlet" transmission is needed to increase the bulk capability of the backbone transmission grid. Lastly, increases in larger region-to-region capacity could be required to deliver large amounts of wind from the Midwest to points east.[28]

The cost of new transmission lines and ancillary equipment depends on a number of factors, including the length of the line, the voltage level, whether it is in an existing or new right of way, and the nature of the ancillary equipment required to interconnect a new line. Such ancillary equipment includes the substations that serve as the termination or through point for any given transmission line, and the equipment contained in those substations (e.g., circuit breakers, transformers, reactive support equipment, metering, etc.). New transmission capacity can also be obtained through thermal upgrade (i.e., new conductors) of existing transmission circuits, at lower cost than a new circuit in a new or existing right of way. Other types of incremental improvements to existing transmission circuits can lead to increased capacity, for example through improvements to reactive power attributes of transmission lines, such as installation of series compensation or shunt capacitance. Lastly, changes to network configurations (e.g., substation bus reconfiguration) or operational changes such as selective use of Special Protection Systems (SPS) can increase the rated capacity of a transmission circuit and enable greater power transfers even without adding new transmission conductors.

Generic Transmission Costs: EIPC

One example of "generic" transmission costs, which are developed for the purpose of estimating certain project costs or scenarios, comes from the Eastern Interconnection Planning Collaborative (EIPC). EIPC has developed many scenarios of transmission build-out plans for the eastern US. These scenarios are based on future potential policies including a "Business as Usual" scenario and others with varying degrees of environmental regulation, including federal carbon regulations and a federal renewable portfolio standard (RPS). EIPC subjects these scenarios to sensitivities on reliability, production costs, and load growth (among others).

Table 3 below shows EIPC's assumptions for transmission costs stated as dollars per mile by amount of voltage as a national average.[29] It also shows the multipliers EIPC develops to generate

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relatively smaller increments of transmission capacity increase can be achieved quickly, at low cost, and with fewer headaches than is seen with new ROW transmission.

[27] See for example the Regional Generation Outlet Study, and related materials, on the Midwest ISO website.

[28] The existing grid delivers supply to load. In the Midwest, as in many regions of the country, much of the supply is coal – which under a number of near-term future scenarios will garner smaller shares of the total electrical energy supply. This departure leaves room on the grid for substitute sources of energy – especially wind and natural gas. The transmission grid does not have to be rebuilt in order to serve increasing amounts of wind energy in the Midwest – it needs to be expanded in some locations, but from a technical perspective, the transmission itself is indifferent to the source of the power it carries. Especially if peak transmission load requirements can be minimized (through energy efficiency, demand response, and local peaking resources) the amount of new transmission needed can also be reduced, in some instances quite dramatically.

[29] We use EIPC transmission costs because they are recent, transparent, public, and broadly representative of the types of transmission equipment that will be needed to integrate more Midwest region wind. Other sources exist, such as that used for the Eastern Wind Interconnection and Transmission Study (EWITS) and the Joint Coordinated System Plan (JCSP) study of increased transmission needs for wind delivery.

costs by NEEM region,[30] of which there are six in MISO. Applying the low and high ranges of these multipliers to the average cost per mile produces a low and high range of region-specific costs for transmission projects in MISO.

Table 3. EIPC Transmission Cost Assumptions by NEEM Region

Voltage (kV)	# of Circuits	MW Capability	Base Cost	MISO_IN	MISO_MI	MISO_MO_IL	MISO_W	MISO_WUMS
			Cost per Mile	Regional Multipliers				
<230	1	300	$1,100,000	0.5 - 1.6	0.5 - 1.6	0.5 - 1.6	0.5 - 1.6	0.5 - 1.6
230	1	600	$1,150,000	0.4 - 0.9	0.4 - 0.9	0.4 - 0.9	0.4 - 0.9	0.4 - 0.9
230	1	900	$1,580,000	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9
230	2	1200	$1,800,000	0.7 - 1.5	0.7 - 1.5	0.7 - 1.5	0.7 - 1.5	0.7 - 1.5
345	UG	500	$19,750,000					
345	1	900	$2,100,000	0.5 - 0.8	0.5 - 0.7	0.3 - 0.6	0.5 - 0.7	0.5 - 0.8
345	1	1800	$2,500,000	0.6 - 0.8	0.6 - 0.7	0.4 - 0.6	0.6 - 0.7	0.6 - 0.8
345	UG	1800	$25,000,000					0.7 - 1.0
345	2	3600	$2,800,000	0.7 - 0.8	0.7 - 1.0	0.7 - 0.8	0.7 - 0.9	0.9 - 1.0
345	UG	3600	$28,000,000					0.7 - 1.0
500	1	2600	$3,450,000	0.5 - 0.7		0.5 - 0.7	0.5 - 0.7	0.6 - 0.8
765	1	4000	$5,550,000	0.5 - 0.7	0.5 - 0.9	0.5 - 0.6	0.5 - 0.6	0.6 - 0.7
HVDC	bipole	2400	$2,150,000	1.0	1.0	1.0	1.0	1.0
HVDC	bipole	2400	$7,500,000					0.7 - 1.1
HVDC Terminal (both ends)			$340,000,000	1.0	1.0	1.0	1.0	1.0

Testing the Accuracy of Generic Cost Projections in MISO

Transmission costs can vary, as seen in the above table, both for regional cost differences and for technical configuration reasons. To put these generic costs in perspective, we've examined a selection of MISO planned transmission projects from the MTEP 2011 report appendices. Those appendices contain significant detail, including cost information on all of the projects under consideration in MISO.

Table 4 below contains a selection of MISO Multi-Value Projects, with attendant "cost per mile" summary information. As seen, the estimates provided in Table 3 (above) are roughly in line with the sample of MVP portfolio projects presented in Table 4.

Table 4. Summary Cost and Cost per Mile of Sample Transmission Projects in MTEP 2011

MVP	State	Voltage	Cost, millions	Mileage	Millions $/mile
Brookings – Twin Cities	MN/SD	345	695	200	3.5
Badger-Coulee and Dubuque-Cardinal	WI	345	714	280	2.6
Winco-Lime Creek-Hazelton	IA	345	480	189	2.5
Adair-Ottumwa	IA/MO	345	152	71	2.1
New Reynolds - Greentown	IN	765	245	66	3.7

Source: MISO MVP Project Listing, Various sources for mileage. $/mile computation by Synapse.

[30] NEEM is the modeling tool used by EIPC to estimate the impacts on transmission need of new resource scenarios for future years. A "NEEM region" is a particular grouping of geographical / electrical areas in the eastern US.

We observe the following with respect to new transmission costs in the Midwest region:

- Generally, the generic costs (such as those used in the EIPC process) are reasonable indicators of transmission costs, given the costs of MISO MTEP 2011 transmission projects.
- Usually, higher voltage transmission is more cost-effective, because it can deliver more megawatts of transfer capacity per dollar of transmission expenditure than lower transmission voltages. This is a result of basic economies of scale. However, if the presence of higher voltages is not already in place in a given region, introducing the high-voltage lines will require building out a basic infrastructure to support such large lines, and may require significant reinforcement of lower-voltage facilities in nearby regions. This effect can offset the technical economies of scale seen with the higher voltage facilities, and is an artifact of the networked nature of the electrical transmission grid.

C. Incremental Transmission Costs: Retail Rate Impacts of New Midwest Transmission

MVP Costs, Revenue Requirements, and Retail Rate Impact

In this section we examine the retail rate impacts associated with MISO's approved Multi-Value Projects portfolio.[31] The MVP portfolio consists of a collection of 17 high-voltage projects, one at 765 kV, and sixteen at the 345 kV voltage level.[32] These projects will better knit together the existing transmission grid in the MISO region and allow for delivery of greater levels of wind energy to the MISO grid. MISO states that the completion of all of the projects in the portfolio (estimated for 2018) will allow for the delivery of an additional 41 million MWh/year of renewable energy.[33] Depending on loading conditions in the region, and supply resources in place in 2018, the MVP portfolio completion could allow for delivery of more than this base amount. The MVP portfolio serves as a starting point for a bolstered MISO grid by strengthening the weakest links in the region, and allowing for concentrations of wind energy to be delivered to the broader grid, for ultimate delivery (along with other supply resources) to MISO region customers. According to MISO, the MVP portfolio will enable access to low-cost energy.[34]

Our analysis of retail rate impacts starts with the findings presented in Appendix E.3 of the MTEP 2011 draft report. The MISO retail rate impacts inform our analysis of retail rate impacts associated with this report's transmission scenarios, which include transmission expansion beyond the MVP portfolio and MISO's projected baseline reliability upgrades.

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[31] Detailed information on the MVP portfolio is available at https://www.midwestiso.org/Planning/Pages/MVPAnalysis.aspx.

[32] MTEP 2011, page 45-46.

[33] MTEP 2011, page 3. 41 million MWh of wind energy at an average of 35% capacity factor equates to roughly 13.4 GW of installed wind capacity.

[34] See, for example, Midwest ISO, MVP portfolio summary posting concerning defined renewable energy zones. "When connected to the overall grid by the MVP projects, the zones will enable access to low cost energy for the entire MISO footprint". October 25, 2011. https://www.misoenergy.org/Library/Repository/Communication%20Material/Power%20Up/Transmission%20Planning%20MVP.pdf.

MISO analyzed the total retail rate impacts of four energy policy scenarios. MISO's total rate analysis included examination of transmission costs and the other major components of electricity bills: supply resources (generation) and distribution costs. In this way, MISO was able to estimate the fraction of customer bills that will go towards transmission support once the MVP portfolio installation is complete. These policy scenarios are as follows:

- **Business as Usual: Mid-low demand and energy growth** (BAU Mid-Low). Under this scenario, MISO assumes that energy growth follows a growth rate of 0.7 percent. This scenario assumes that MISO will experience a slow recovery from the economic downturn. It also assumes little to no change in resource adequacy, renewable mandates, and environmental legislation.
- **Business as Usual: Historical demand and energy growth** (BAU Historical). Under this scenario, MISO assumes that energy growth follows a growth rate of 1.33 percent. This scenario assumes that MISO will experience a more rapid recovery from the economic downturn. This scenario also assumes little to no change in resource adequacy, renewable mandates, and environmental legislation.
- **Carbon Constraint**: Under this scenario, MISO assumes that energy growth follows a growth rate of -0.06 percent. However, in this scenario, MISO further assumes a declining cap on future CO_2 emissions based on the Waxman-Markey bill. MISO assumes for its 2026 rate impact analysis that there is a 25 percent target reduction.
- **Combined Energy Policy**: Under this scenario, MISO modeled the combined impacts associated with smart grid penetration that would lower demand growth, coupled with higher electric vehicle penetration that would increase energy growth and off-peak energy usage. Under this scenario, MISO assumes an energy growth rate of 0.56 percent (consistent with the BAU Historical scenario).

The four policy scenarios result in different projections of "energy served values" in 2026, which are the denominator for calculating rate impacts, since the MVP portfolio will be paid for using a "postage stamp" allocation process that would spread the costs of transmission across all users in MISO. For our additional transmission alternatives analysis, we assumed the same energy served projections used by MISO in their BAU Mid-Low policy scenario.

Under each of the four policy scenarios, MISO assumed the same 2026 revenue requirements for the following rate components:

- MISO Existing Transmission: 2026 revenue requirement of $1.670 billion in 2011$[35]
- Proposed MVP Portfolio: 2026 revenue requirement of $1.045 billion in 2026$.
- MISO Existing Resources Capital Recovery: 2026 revenue requirement of $6.384 billion in 2011$[36]
- Distribution: MISO assumes a distribution adder of 2.6 cents/kWh in its analysis.

[35] Based on email exchange with MISO, the values presented in TablesE.3-8 and E.3-11 are in 2011$, although labeled in the draft report as 2026$.
[36] Ibid.

The other components of MISO analysis vary based on its policy scenario assumptions as noted above.

The following table summarizes the MISO-estimated retail rate impacts of the MVP transmission alternative, for each of their four policy scenarios.

Table 5. MISO Rate Impacts for the MVP Portfolio

	MTEP 2011 Scenarios			
Year/ Category	**BAU Mid-Low Demand & Energy Growth**	**BAU Historical Demand & Energy Growth**	**Carbon Constraint**	**Combined Energy Policy**
	MISO Energy Served (MWh)			
2011	533,879,900	533,799,100	533,646,300	533,532,600
2026	592,765,700	650,439,800	528,947,100	580,162,000
Revenue Requirements (2026$ unless noted)				
Proposed MVP Portfolio	$1,045,330,421	$1,240,912,795	$1,045,330,421	$1,240,912,795
Future Reliability Requirements	$1,758,130,148	$1,758,130,148	$1,758,130,148	$1,758,130,148
MISO Existing Transmission (2011$)	$1,670,449,654	$1,670,449,654	$1,670,449,654	$1,670,449,654
Production Costs	$12,768,400,000	$20,674,200,000	$16,339,400,000	$20,522,400,000
New Resource Investment	$5,470,200,000	$7,284,700,000	$5,109,400,000	$7,220,700,000
Fixed O&M	$14,136,000,000	$18,656,900,000	$15,416,200,000	$24,894,600,000
MISO Existing Resources Cap. Rec. (2011$)	$6,384,800,464	$6,384,800,464	$6,384,800,464	$6,384,800,464
Retail Rate (Cents/kWh 2011$)				
Proposed MVP Portfolio	0.14	0.12	0.15	0.14
Future Reliability Requirements	0.30	0.27	0.33	0.30
MISO Existing Transmission (2011$)	0.28	0.26	0.32	0.29
Total Transmission	**0.71**	**0.65**	**0.80**	**0.73**
Production Costs	1.66	2.07	2.38	2.30
New Resource Investment	0.71	0.73	0.75	0.81
Fixed O&M	1.84	1.87	2.25	2.79
MISO Existing Resources Cap. Rec. (2011$)	1.08	0.98	1.21	1.10
Total Generation	**5.29**	**5.64**	**6.59**	**7.00**
Distribution	**2.61**	**2.61**	**2.61**	**2.61**
Total Retail Rate	**8.62**	**8.90**	**10.00**	**10.34**
Inflation Rate	1.74%	2.91%	1.74%	2.91%
2026$ to 2011$ Factor	0.772	0.650	0.772	0.650

Notes: Information based on Appendix E3. Values in 2011$ based on email from Jeremiah Doner dated October 25, 2011

Overall, the retail rate impact from MISO's MVP portfolio and associated supply assumptions over the four policy scenarios range from 8.62 to 10.34 cents/kWh, with the transmission component ranging from 0.65 to 0.80 cents/kWh or seven to eight percent of the overall retail rate impact. These results suggest that MISO's proposed transmission build–out, including the approved MVP portfolio and an estimate for future baseline reliability transmission,[37] would have a minor impact on overall retail rates under MISO's analysis.

New Transmission Above and Beyond MVP

In this section we estimate retail rate impacts for three scenarios of transmission cost beyond the improvements that accompany the MVP portfolio. These scenarios are based in large part on the costs of three "indicative transmission" results obtained by MISO and the stakeholder group during its Regional Generation Outlet Study (RGOS) process.[38] The three expansion scenarios chosen represent 1) a 345 kV expansion focus[39], 2) a 765 kV expansion focus, and 3) a combined 765 kV plus high-voltage DC expansion focus. Each of these scenarios would allow for successively higher levels of wind to be integrated into the system, although we are using these scenarios primarily as a benchmark for expansion costs, not as a means to map a specific transmission expansion scenario to a particular wind resource build out. The RGOS process included a set of analyses of transmission alternatives that could be required to deliver greater levels of wind energy to the MISO grid. The three scenarios for which we develop rate impacts represent low, medium, and high transmission expansion scenarios for the MISO region.[40] For the purposes of our study, these scenarios are labeled as the Synapse Low, Medium, and High T Expansion scenarios.

It is important to note that this analysis does not seek to answer the question of how much transmission is needed to enable greater levels of wind. Determining with any certainty how much transmission would be required by 2021, or by 2031, to integrate a given amount of wind is a complex planning exercise that depends in large part on the load and supply resource mix assumed, and the locations of resources. We have not conducted such an exercise.

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[37] Baseline reliability transmission can be thought of as the minimum transmission requirements necessary to maintain reliable operation of the grid. The level of such requirements will depend heavily on the assumptions used for design peak loading level, and the set of reliability standards to which the grid is planned. Those standards are primarily the mandatory NERC standards in place since the transition from voluntary utility compliance with reliability standards (pre-2005, before the federal Energy Policy Act with transmission reliability features) to mandatory compliance.

[38] A summary of "indicative transmission results" is presented on page 32 of the RGOS report. The detailed listing of transmission mileage and cost estimation is given in Appendix 3, "Indicative Transmission Design".

[39] We note that even though the Midwest is a very likely candidate for an expansion that utilizes 765 kV equipment (to capture economies of scale, and to acknowledge the vast distances involved with Midwestern wind transmission) other regions have undertaken expansions that have first focused on just 345 kV equipment. New England is a good example. Utilizing a postage-stamp cost allocation method arising from the region's history of cooperation among utilities (the New England Power Pool predated the current New England ISO), New England has successfully planned, paid for, and built or is building significant segments of 345 kV increases in Connecticut, Massachusetts, Maine, and New Hampshire. This collaboration among utilities on cost allocation and planning methodologies serves as a useful reference to Midwest states grappling with cost allocation issues.

[40] The indicative designs we use as a benchmark here were developed in the RGOS process "without the use of system modeling or analysis; rather, the task was achieved by harnessing the collective knowledge of workshop participants, all experienced transmission planners. …the point of the exercise was to develop transmission that could "indicatively" provide a solution." Page 30, RGOS report. We note that some of the modeling results that were relied upon as input to the RGOS process included modeling processes that assume particular peak loading levels (MTEP 2009 vintage) and a supply resource base with minimal coal plant retirement. In our analysis, we assume transmission expansion scenarios that would be in place with significantly increased levels of wind, retirements of at least a minimal level of coal, and additions of gas-fired capacity. We also use more recent peak load projections (MTEP 2011), which are considerably different (lower) than those of MTEP 2009. All of these changes would influence the ultimate level of wind which could be delivered using these indicative designs. We do not attempt to rigorously assess the range of wind that could be integrated given such an expansion, as it is beyond the scope of our modeling and rate impact process.

Instead, the analyses conducted for this report focus on transmission rate impacts and supply-induced price effects in the Midwest market. Both the rate impacts and the market price effects will depend on the level of transmission and the level of wind added to the Midwest grid. We address in part the question of "how much wind" by modeling successive 10 GW increments, up to a total of 110 GW of installed Midwest wind, in our market price effect model, as we explain in Section 4 of this report. We address the question of "how much transmission" by assuming three different expansion levels beyond the MVP portfolio, using the RGOS report as a rough cost benchmark.

It is likely that the ultimate makeup of the transmission grid expansion will not look exactly like the three expansion scenarios we use as benchmarks here. The final location of the wind resource additions and the pattern of existing plant retirement and new gas-fired plant location will have a large influence on the transmission expansion particulars. To the extent that wind resource output can utilize "headroom" on the grid created by changing patterns of fossil resource base use, less transmission could be needed. To the extent that new wind locations are far from the backbone grid, more expansion could be needed. Without conducting a new round of RGOS-like studies incorporating considerably changing fossil resource bases into the supply mix and changing load projections, it is difficult to gauge just how large an expansion will actually be needed.[41]

Additionally, we note that Midwest region grid expansion historically has been tied to summer peak load needs, a time when wind resource output is generally at its seasonal minimum. This implies that factors *in addition to* total installed wind quantities contribute to any need for the regional expansion of the transmission grid.

Revenue Requirements and Retail Rate Impact for Three Scenarios

The three transmission expansion scenarios studied by Synapse include:

- **Synapse Low T Expansion scenario:** Based on the RGOS "Combo" (75/25, or 50/50) 345 kV, this scenario would provide incremental transmission across the MISO grid with a focus on 345 kV lines, but with some 765 kV additions in Indiana and Michigan. The 75/25 is a reference to the split in source locations for renewable energy—in this case, a "combination" of either 75% from the "west" states in MISO and 25% from the east states, or 50% from the west and 50% from the east. The RGOS report indicates that the total costs of the 'combination 345 kV' build-out are roughly the same regardless of whether the sourcing split is 75/25 or 50/50.
- **Synapse Medium T Expansion scenario:** Based on the RGOS "Combo" (75/25) 765 kV, this scenario contemplates a much greater level of 765 kV resources in MISO to deliver 75% of the MISO renewable requirements from western regions of MISO.
- **Synapse High T Expansion scenario:** Based on the RGOS Regional 765 kV DC West Optimized, this scenario includes two major HVDC lines between the western part of

[41] We note that the EIPC modeling process produced a number of sensitivity runs that called for minimal expansion of the grid between major eastern interconnection regions by 2030, while still supporting large increases in wind. For example, F8S5 showed only half the total transmission expansion as was seen in F8S7, one of three scenarios chosen for continuing analysis in Phase II of the EIPC process. That result illustrated, at a high level, that peak load level and the mix of other generation resources can considerably affect indicated transmission need, even within the restricted bounds of a single EIPC Future. We do note, however, that those analyses excluded "within" region transmission costs, which would add cost to any transmission expansion scenario, although to some extent the "reliability" transmission cost included in our estimate would cover some of this need.

MISO (source points at the Minnesota border with South Dakota, and in northwestern Iowa) and the eastern part of MISO (termination points in northern and southern Illinois), plus additional 765 kV AC expansion throughout the MISO region.

Synapse calculated revenue requirements for these scenarios based on the methodology used by MISO to calculate future reliability investments, which is described in Section E.3.2.2.2 of Appendix E.3 of the MTEP 2011 report.

Synapse's scenario analysis calculates revenue requirements using the following methodology, which follows from MISO's computational methods for the MVP portfolio.

Inflation: The inflation rate is the MTEP 2011 BAU Mid-Low scenario rate of 1.74 percent, based on Footnote 2 of Appendix E.3.

Charge rates: The annual charge rate uses 19.8 percent for the first year of recovery and then declines by 0.3 percent each subsequent year. This charge rate includes depreciation following a 40-year straight-line depreciation schedule. In addition, the charge rate includes transmission return on investments.[42]

MISO Energy Served: We used MISO assumptions for an energy (kWh) load growth of 0.7% per year between 2011 and 2030. This is the BAU Mid-Low scenario rate for energy.

Table 6 (below) contains the results of our rate impact analysis for different transmission build-out scenarios. The table includes four components of costs for transmission:

1. Existing transmission in rate base;
2. New MVP portfolio costs;
3. Future "reliability" transmission needs (or, transmission required due to ongoing supply resource changes, load increases as projected by MISO, or related reliability criteria); and
4. Increments of transmission needed to integrate larger levels of wind onto the MISO grid.

It does not include transmission that would likely be required in other regions—in particular PJM—if large levels of MISO wind are ultimately connected to the grid to serve either local renewable portfolio standard needs or more distant region needs. Simultaneously, it allocates the costs of transmission only to MISO members, and in that respect represents a conservatism, since it is possible, if not likely, that external MISO users would contribute more toward the specific costs shown in the table than is currently estimated by MISO (in its schedule 26a allocation[43]).

[42] Based on conversation with Jeremiah Doner of MISO on December 16, 2011.
[43] Schedule 26a of the MISO tariff contains estimates of the energy withdrawal levels, by year, for MISO members. These withdrawal levels are the allocator for MVP portfolio costs.

Table 6. Estimates of MISO Member Rate Impacts for New MISO-Region Transmission to Facilitate Delivery of Future Wind onto MISO Grid

Future Transmission Scenario	Transmission Investment Timeframe	Transmission Investment Cost, $Billions ($2011)	Transmission Rate Impact of Scenario Listed, for Year Listed, cents/kWh, $2011			Share of Transmission Rate by Component (Existing, MVP, Future Reliability, Future Indicative)		
			2015	2021	2031	2015	2021	2031
Current MVP Only								
Existing Transmission (based on trend - MISO 2011 and 2026 Rev	Current Rate		0.53	0.39	0.17	68%	48%	29%
MVP Portfolio	2012-2018	5.2	0.10	0.16	0.13	13%	20%	22%
Future Transmission - Reliability	2011-2026	11.2	0.15	0.26	0.29	19%	32%	50%
Future Indicative Transmission – Synapse Scenario	NA	0.0	0	0	0	0%	0%	0%
Total New Investment $; and Transmission Rate Impact		16.4	0.78	0.81	0.58	100%	100%	100%
Current MVP + Synapse Low T Expansion								
Existing Transmission (based on trend - MISO 2011 and 2026 Rev	Current Rate		0.53	0.39	0.17	68%	35%	15%
MVP Portfolio	2012-2018	5.2	0.10	0.16	0.13	13%	14%	11%
Future Transmission - Reliability	2011-2026	11.2	0.15	0.26	0.29	19%	23%	26%
Future Indicative Transmission – Synapse Low T Expansion	2018-2025	19.0	0	0.32	0.52	0%	28%	47%
Total New Investment $; and Transmission Rate Impact		35.4	0.78	1.14	1.11	100%	100%	100%
Current MVP + Synapse Medium T Expansion								
Existing Transmission (based on trend - MISO 2011 and 2026 Rev	Current Rate		0.53	0.39	0.17	62%	32%	13%
MVP Portfolio	2012-2018	5.2	0.10	0.16	0.13	12%	13%	10%
Future Transmission - Reliability	2011-2026	11.2	0.15	0.26	0.29	18%	21%	22%
Future Indicative Transmission - Synapse Medium T Expansion	2015-2028	26.0	0.07	0.43	0.72	8%	35%	55%
Total New Investment $; and Transmission Rate Impact		42.4	0.85	1.24	1.30	100%	100%	100%
Current MVP + Synapse High T Expansion								
Existing Transmission (based on trend - MISO 2011 and 2026 Rev	Current Rate		0.53	0.39	0.17	62%	30%	11%
MVP Portfolio	2012-2018	5.2	0.10	0.16	0.13	12%	13%	8%
Future Transmission - Reliability	2011-2026	11.2	0.15	0.26	0.29	18%	20%	18%
Future Indicative Transmission - Synapse High T Expansion	2015-2031	35.0	0.07	0.48	0.99	9%	37%	63%
Total New Investment $; and Transmission Rate Impact		51.4	0.86	1.29	1.58	100%	100%	100%

Notes and Sources: Transmission Scenario costs approximate, based on MISO Regional Generation Outlet Study (November 19, 2010), Appendix 3, Indicative Transmission Design, A3.5 Combo (75/25) 345 kV, page 10; A3.6 Combo (75/25) 765 kV, page 12, and A3.12 Regional 765 kV DC West Optimized, page 21. Existing transmission based on MTEP 2011, Appendix E.3, “Retail Rate Impact”, MISO values for 2011 and 2026, interpolated and extrapolated by Synapse to obtain 2015, 2021, and 2031 estimates. MVP portfolio costs from MISO MTEP 2011, Appendix E3 2026 revenue requirements, and Synapse computation of other year impacts using MISO methodology as described in Appendix E3. Future transmission – reliability based on MISO Appendix E3, Table E3.7, and Synapse computation of other year revenue requirements. Future indicative transmission costs estimated based on RGOS indicative costs for scenarios, with revenue requirements computed by Synapse using same methodology as MISO uses for MVP. Assumes all future indicative transmission costs will be allocated “postage stamp” across MISO load. Excludes impacts of alternative cost allocation and contributions from other parties.

Table 6 shows the following:

1. The transmission rate effect for the current MVP portfolio and additional baseline transmission, as indicated by MISO in the MTEP 2011 report and as computed by Synapse (based on revenue requirements), is minimal. It is just above three-quarters of a cent per kWh (0.78 cents/kWh, or $7.80/MWh) in 2015, rising to 0.81 cents/kWh ($8.10/MWh) by 2021. This is seen in the "Total New Investment $; and Transmission Rate Impact" line of the "Current MVP Only" table section. The set of projects that make up the MVP portfolio will be complete before the end of MISO's current planning period (2021). Generally, this level of cost will be on the order of ten percent of the total retail bill. If no additional transmission were added after the MVP portfolio (other than baseline reliability projects), by 2031 transmission rates would decrease to 0.58 cents/kWh ($5.80/MWh).
2. Each (or any) of three successively higher levels of transmission additions beyond the MVP portfolio would increase the transmission component of rates throughout MISO to a total ranging from 1.14 to1.29 cents/kWh by 2021 ($11 to $13/MWh). If a greater level of transmission beyond the "Synapse Low T Expansion" scenario is ultimately required to achieve longer-term goals of wind energy supply, total transmission rates by 2031 could reach 1.30 to 1.58 cents per kWh ($13 to $16/MWh), as seen in the 2031 column for the medium and high Synapse expansion scenarios.
3. Even the significant level of transmission rate increase that would be seen with Synapse's Medium or High expansion scenarios is but a small component of overall consumer electricity rates, which were roughly 8.7 cents per kWh ($87/MWh) in 2011, based on MISO's compilation of retail electricity rates.
4. The columns on the right-hand side of the table illustrate the relative share of transmission costs associated with existing, MVP, future reliability, and future indicative transmission. For example, by 2015 68% of the total (average) transmission rate seen in the MISO region is due to ongoing revenue requirements for existing transmission. Conversely, in the Synapse Low T Expansion scenario, where future indicative transmission costing roughly $19 billion ($2011) would be installed between 2018 and 2025, the rate effect in 2031 is such that existing transmission has depreciated to only 15% of the total transmission rate, and the new transmission makes up 47% of the transmission component of bills.
5. Notably, the table does not contain the effect of offsetting benefits that will be seen in the marketplace as wind resources come online, which is discussed in Section 4 of this report. It serves only to demonstrate the estimated transmission rate component, given the assumptions we have stated.

D. Congestion Costs: Transmission

Transmission congestion occurs when the capacity of the transmission system limits the flow of energy across a given element or interface of the transmission system. In such circumstances, load and supply are kept in balance by using relatively more-expensive-to-operate generation in a region closer to load, rather than using less expensive generation that is located further away from load. The congestion may persist for brief periods (a few hours, or less) or it may be sustained over greater periods of time. Price differences between zones can be an indication of congestion.[44] Another metric used by MISO to portray the extent of congestion on its system is the number of flowgate-hours of congestion, or how often a given flowgate is operated at its limit.[45] A more telling metric for congestion's effects would represent the financial impact of congestion. For example, while MISO's total day-ahead congestion costs in 2010 were almost $498 million[46], financial transmission rights[47] (FTRs) hedged most of these costs—in 2010, the FTR funding shortfall was only $54 million[48], in a total wholesale energy market whose value exceeded $1.5 billion in 2010.[49]

Current MISO-region congestion patterns and resulting costs arise from the underlying demand patterns across the Midwest, the strength (and weaknesses) of the transmission grid, and the placement and operational economies of different types of generation. The MISO region has often seen patterns of west-to-east congestion across its grid, though its overall level of "unhedged" congestion[50] is relatively low. MISO examines its "Top Congested Flowgates" regularly, and seeks to mitigate the effect of congested flowgates in part through transmission planning to alleviate constraints.

The temporal and locational attributes of future transmission congestion in the Midwest ISO region will be different from today's congestion patterns. By 2020, and then again by 2030, wind additions, coal retirements, transmission expansion, and gas-fired peaking (and possibly combined cycle) additions will lead to different—perhaps dramatically different—power flow patterns than are currently in place. Thus, it can be difficult to predict with any certainty what congestion levels may look like in future periods.

Transmission additions tend to alleviate congestion. For the purpose of this analysis, which is focused on the beneficial market-price effects of increased wind resources (and accompanying transmission), we ignore the co-benefit of congestion relief (and reduced transmission losses) brought by transmission, and presume that for any given level of wind additions, congestion effects will not lead to either significant curtailment of wind energy, or to sustained diverging of prices across the Midwest market due to congestion.

Figure 3, below, illustrates the average energy price differences among the four major regions in the MISO area over the past two years, 2010 and 2011. The graphs in Figure 3 show average MISO day-ahead energy market prices, by month and by period (on-peak, M-F 7A-11P; off-peak all other hours), for 2010 and 2011. The patterns show consistently higher energy market prices in

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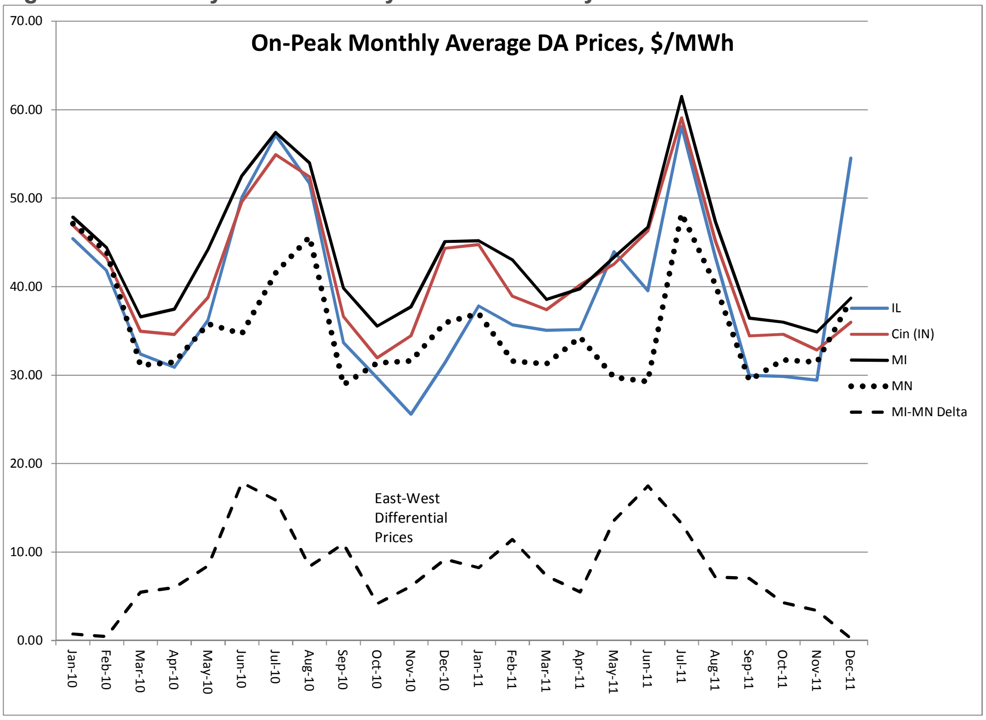
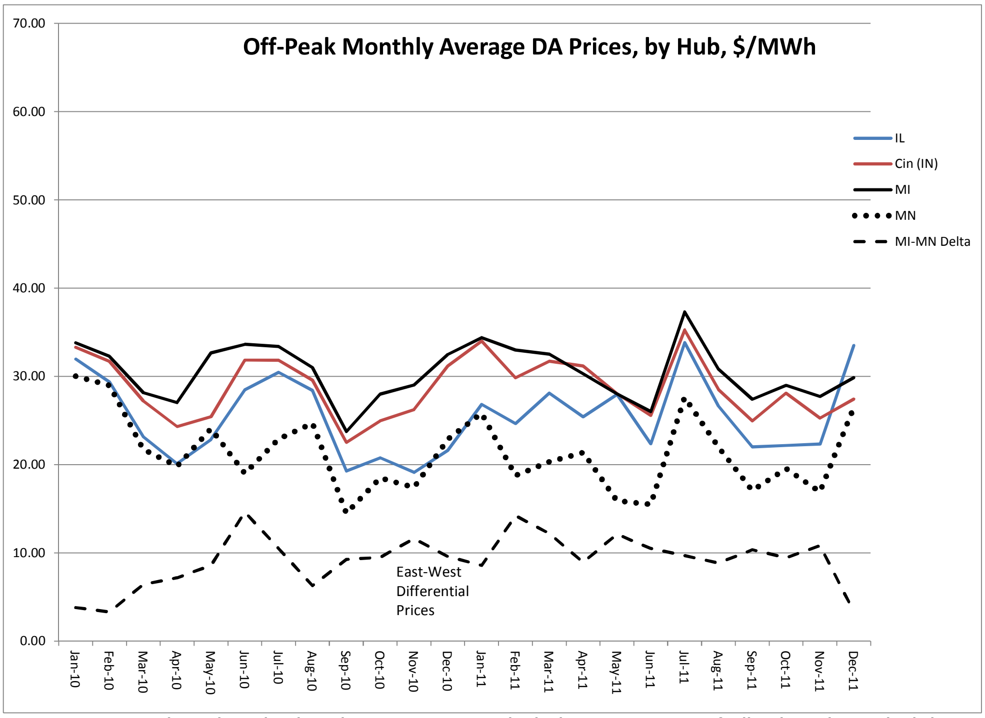
44 Price differences arise from both congestion and transmission loss effects.
45 A flowgate is an element or group of elements of the transmission system, such as a line or group of lines.
46 MISO 2010 State of the Market Report, Figure 50, page 78.
47 Financial transmission rights hedge the holder against congestion costs between two points or two zones. Effectively, FTRs allow a "load" holder to pay the lower "source zone" price for energy delivered across a constrained interface. Conversely, FTRs allow a "supply" holder to obtain a higher price for their power delivered across a congested interface.
48 MISO 2010 State of the Market Report, Figure 51, page 80.
49 The value of the MISO real-time energy market to MISO members is approximated by multiplying the average real-time price in 2010 ($34/MWH, page ix of the 2010 MISO State of the Energy Market report) by the total MISO member load (roughly 500 million MWH in 2010).
50 Unhedged congestion refers to the negative financial effects of physical congestion that cannot be mitigated by holding financial transmission rights (FTRs). FTR availability across a given congested interface is limited to a "feasible set" of FTRs that are equivalent to the carrying capacity of that transmission interface.

the eastern zones, as represented by the "Michigan Hub" and "Cinergy Hub" locations. The "Minnesota Hub" represents the western MISO zone.

Figure 3. MISO Day-Ahead Monthly Price Pattern - by MISO Hub and Peak/Off-Peak Period, 2010-2011





Source: MISO day-ahead price data, Synapse tabulation. Average of all prices in period, by month. On Peak hours: M-F, 7AM–11PM.

Figure 3 shows monthly average price differentials between the east and west regions (bottom, dashed line) that are mostly similar across on-peak and off-peak periods, though the summer periods clearly show higher price differentials during on-peak hours, reflecting higher load. These price differences illustrate that congestion and transmission loss effects give rise to price differences between the regions, and those differences are more pronounced during the heavier loading periods in the summer. While the graphs do not distinguish between "loss" and "congestion" effects that give rise to the price differentials, they do show the predominate pattern of less expensive energy in the west, and more expensive energy in the eastern part of MISO. Transmission improvements between eastern and western portions of MISO will reduce these differences by reducing both transmission losses and congestion.

3. Renewable Energy Economics in the Midwest Energy Market

In this chapter we examine the downward pressure on energy market prices associated with adding more wind power to the MISO grid. We begin by broadly examining the role of renewable energy economics in electric power markets, including the fundamentals of supply and demand, and the nature of the supply-induced price effect (SIPE). We then describe the model used by Synapse to calculate the SIPE in the MISO market region for 2020 and 2030 for a broad range of scenarios with varying input assumptions. We explain the workings of the spreadsheet model, and list the assumptions and data sources used. We report on the results of our modeling processes, and discuss and interpret those results.

A. Overview of Renewable Energy Economics

Renewable energy supplies, in particular wind turbine installations at utility scale, are beginning to upheave the electric power market structure in the MISO region. While Midwest power markets have gone through numerous changes over the years (including a seminal consolidation of balancing areas (2009) after a shift of operational control to MISO in 2005), transitioning to a supply base that is likely to be dramatically less dependent on coal for energy provision will likely be institutionally tumultuous and will have far-reaching effects. The exact pace of this transition remains to be seen, driven in large part by the unfolding policies of (federal) environmental regulation and (state) renewable portfolio standards implementation. The transition would, or will, be further accelerated if or when carbon emission policies are implemented.

While some technically driven, operational challenges will be present, for the most part the hurdles that will accompany the transition away from coal's dominant role as an energy provider and toward greater levels of wind (over the next decade and beyond) are not particularly difficult to clear. Integrating wind resources onto the Midwest region grid requires transmission to interconnect the wind resources, sufficient levels of operating reserve, and concomitant levels of reliable capacity. While wind provides some reliable capacity[51], it serves predominantly as a provider of energy, or kWh. Wind integration will be made easier as three events continue to unfold: 1) improved interregional coordination and forecasting,[52] 2) expansion of the transmission grid, and 3) increased overall flexibility of the supply resource base[53]. This last element essentially means reduced dependence on slower-ramping resources to provide load-following

[51] MISO currently affords wind a 12.9% capacity credit (Planning year 2011, per the "Planning Year 2011 LOLE Study Report"). This means that 12.9% of the installed capacity of wind can be counted towards resource adequacy requirements, or planning reserve. Depending on the overall level of wind resource penetration, and the choice of "wind and load synchronized hourly pattern" (page 56 of the LOLE Report), the range of capacity accreditation is estimated to be somewhere between roughly 10% and 20%.

[52] We note that integration will be most efficient as the best available wind and load forecasting tools are used and incorporated into dispatch operations and unit commitment processes, and as scheduling and dispatch coordination between MISO and adjacent regions improves.

[53] The availability and presence of demand-side response, and the effects of energy efficiency will also be critical to patterns of pricing in the MISO energy market. This analysis focuses on supply resource effects on price, given projected demand levels.

capacity, and increased dependence on faster-ramping resources, including but not limited to gas-fired turbines and/or combined cycle units.[54]

Wind as a supply resource has been getting steadily cheaper. Its technical performance characteristics continue to improve, as larger turbine sizes and higher hub heights capture both economies of scale and more of the passing wind. While such "turbine scaling" has increased the cost per kW of turbines over the past decade, it nonetheless has translated into lower overall levelized cost of energy for wind resources, in part because of increased performance (capacity factor increases).[55] Simultaneously, the projected cost of coal-fired power has begun to increase, primarily due to the costs required to retrofit coal plants to meet more stringent environmental regulations. These cost increases alone—separate from the effect of possible carbon emission policies—led to a modeling result of over 80 gigawatts of Eastern Interconnection coal-fired resource retirement by 2020 (including more than 12 GW in MISO) in the "business as usual" case of the US DOE-sponsored Eastern Interconnection Planning Study.[56] EIPC study scenarios that modeled the pricing of carbon emissions led to even greater levels of coal retirement, with most occurring in the nearer term (by 2020).[57]

To provide the context for Midwest-region renewable energy economics, we include three figures that illustrate the geographical relationship between wind and transmission in the MISO region. Figure 4, below, shows the relative strength of the wind resource base throughout the region.

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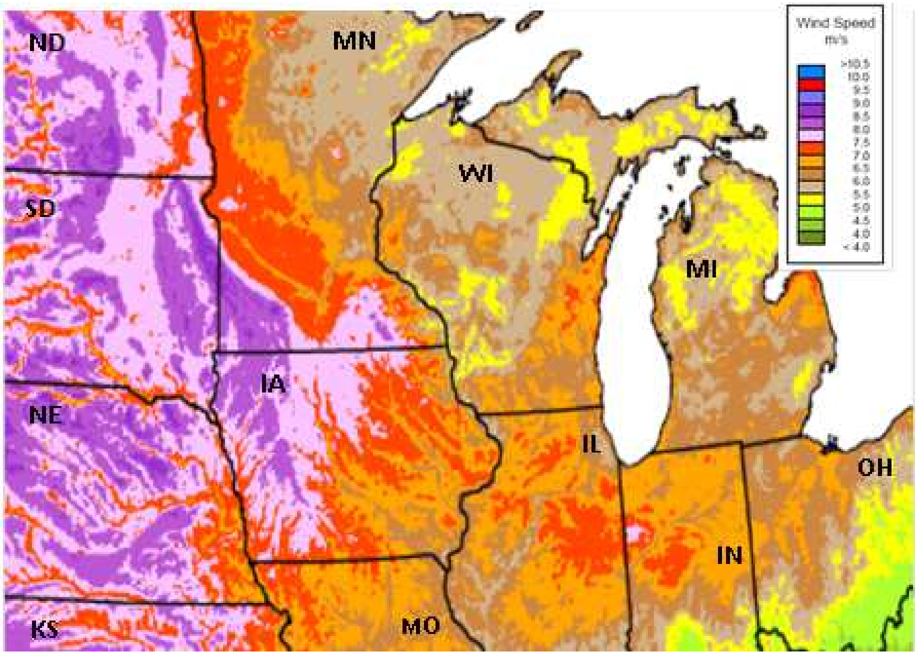
[54] Hydroelectric resources, imports with more frequent scheduling timelines, and some demand response resources can also provider relatively faster-ramping capacity than some of the existing baseloaded generation.

[55] Bolinger, Mark and Ryan Wiser, Lawrence Berkeley National Laboratory, "Understanding Trends in Wind Turbine Prices Over the Past Decade," October 2011. Report LBNL-5119E. See Section 3.4, page 12-15. Also see Wiser, Ryan, Eric Lantz, Mark Bolinger and Maureen Hand, "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects," February 2012. Available at http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf.

[56] See for example Table 5, page 49 http://www.eipconline.com/uploads/Phase_1_Report_Final_12-15-2011.pdf

[57] See for example the summary results of the macroeconomic modeling of the "National Carbon" scenario, p. 50 ("In comparison to the BAU, additional coal plants are retired in the early years and replaced largely with CCs").

Figure 4. Wind Resource Map: Midwest



Source: NREL 80-meter Wind Map

This figure was reproduced from a portion of the NREL 80-meter wind resource map, and shows that the “best” wind resources (i.e., the highest wind speed regimes) are located in the western MISO areas, and especially in the regions of the Dakotas, western Minnesota, and Iowa. However, commercially viable wind regimes extend throughout all of the MISO states, as wind speeds that average 7.0 to 7.5 meters/second (m/s) represent class 3 through class 5 wind regimes that can produce wind power at levelized costs that could be as low as $60 to $70/MWh, without tax incentives.[58]

Figure 5 shows the locations of each of the 17 transmission projects that make up the MVP portfolio. It illustrates a pattern of planned improvement that connects regions in a west-to-east direction, helping to bring wind energy from the oval “renewable energy zones” to the existing transmission grid.

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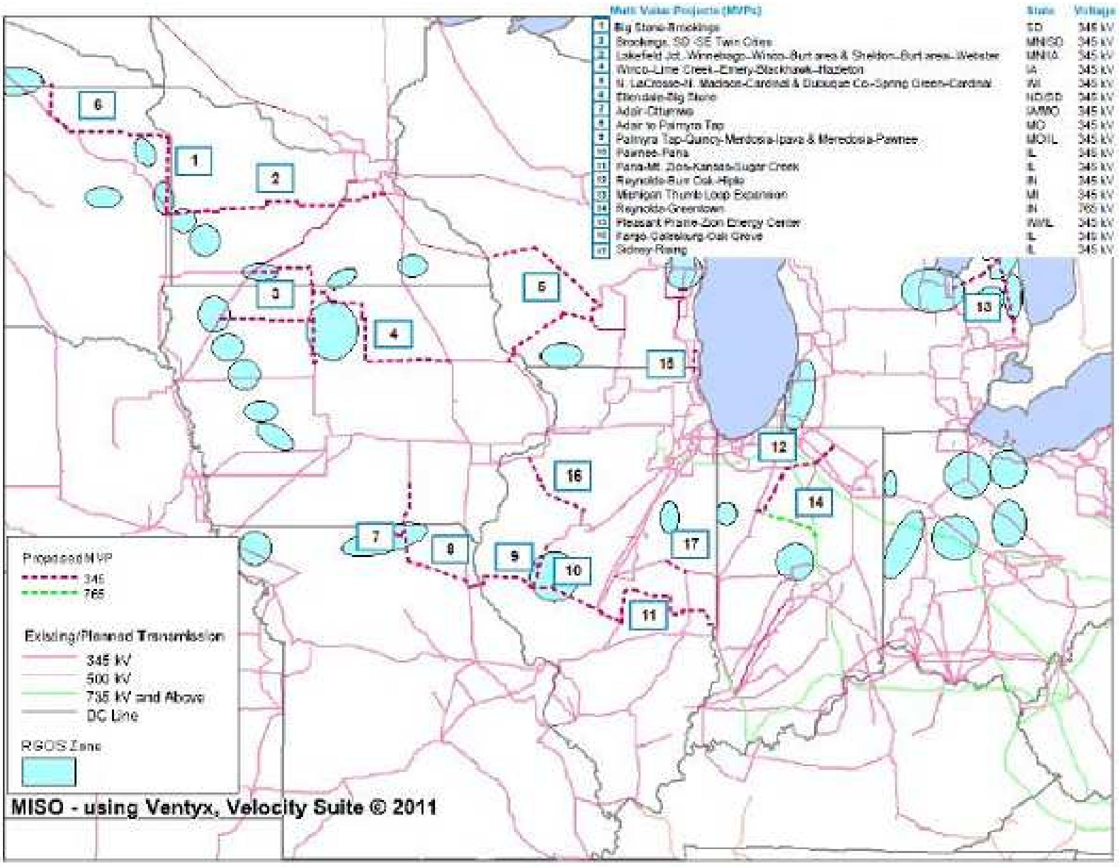
[58] See Wiser, Ryan, Eric Lantz, Mark Bolinger and Maureen Hand, "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects," February 2012. Slide 36. Available at http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf.

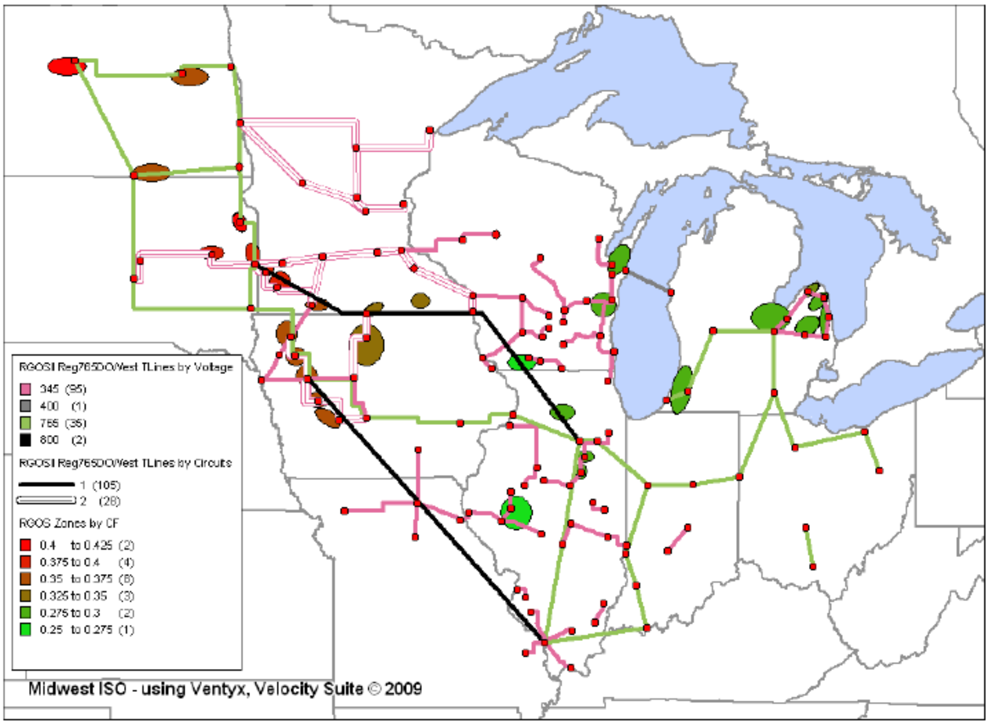
Figure 5. MISO Renewable Energy Zones, and the MVP Portfolio of Transmission



Source: MISO MVP Portfolio Report

Figure 6 (below) illustrates the geographical characteristic of the RGOS buildout on which the Synapse High T Expansion scenario costs are benchmarked, which is referenced in Section 3 of this report. It shows an expansion that builds upon the MVP portfolio build-out. In brief, the Synapse High T Expansion scenario is based on a 765 kV network in the MISO region that allows for collection of much larger levels of wind injection than would be seen with solely a 345 kV reinforced grid. It also includes two "express" DC lines that would allow for large volumes of power to be shipped across the MISO region from west to east, connected on the eastern end to a bolstered 765 kV grid that spans the central and eastern MISO region. We include this graphic here to demonstrate the type of expansion beyond the MVP portfolio that is under consideration in the Midwest.

Figure 6. MISO's RGOS Regional 765 kV DC West Optimized Buildout



Source: MISO RGOS Report, Appendix 3 Indicative Design, Figure A3. 12-1, page 22.

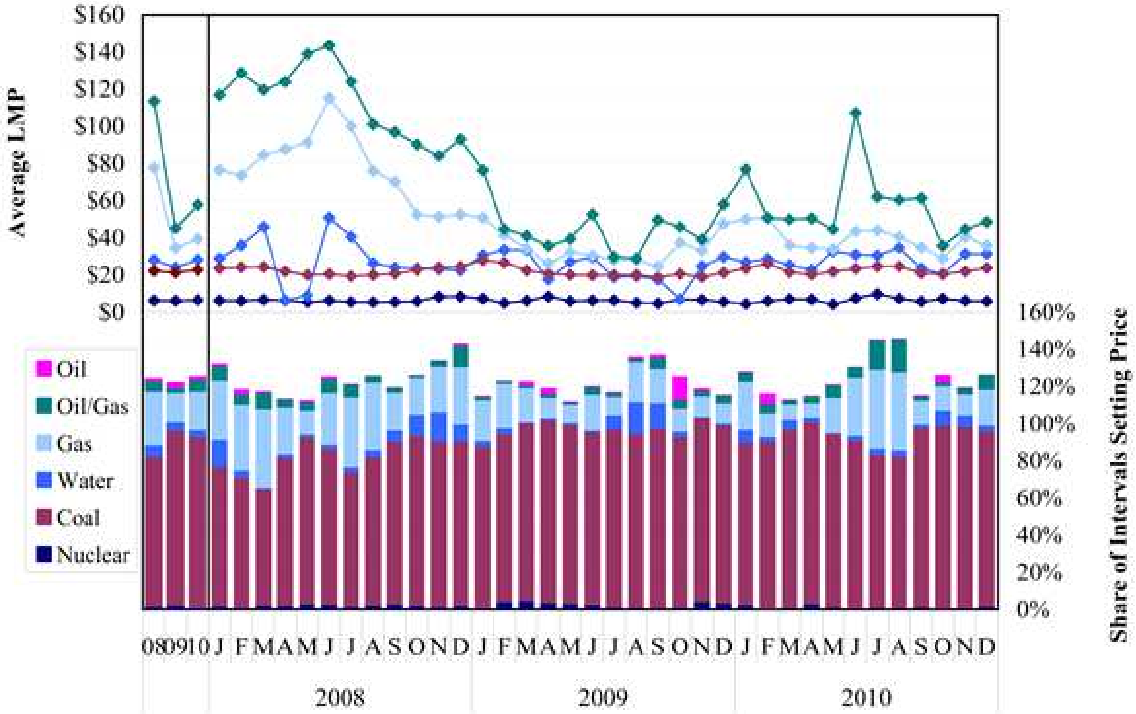
B. Supply-Induced Price Effect

The supply-induced price effect in electricity markets (such as the MISO energy market) is an artifact of the fundamentals of supply and demand. It arises from the introduction of additional, low- or zero-marginal-cost energy supply (such as wind) that results in less-costly operation (on the margin) to clear the demand in any given dispatch (real-time) interval or day-ahead market interval. The MISO market is currently composed of large quantities of coal and gas-fired generation whose operating characteristics and position on a MISO system supply curve are such that they set the clearing price for most intervals of the MISO energy market. Figure 7, below, from the Midwest ISO 2010 State of the Market Report, clearly shows the dominance of coal and gas as price-setting fuels in the Midwest market. The right-hand y-axis (i.e., share of intervals setting price) is greater than 100% for most intervals because more than one fuel can set the clearing price in an interval when more than one transmission constraint is binding.[59] The MISO Market

[59] The MISO energy market is a locational marginal price (LMP) market. The market price in any given clearing interval is made up of three components – the marginal cost of energy, the marginal cost of congestion (MCC) and the marginal cost of losses. The presence of binding transmission constraints in any pricing interval (hourly for the day-ahead market, 5-minutes for the real-time market) causes the MCC to be greater than zero for that interval.

Monitor noted the supply-induced price effect in the 2010 State of the Market Report, recognizing that one result is that coal-fired resources were on the margin more often in 2010.[60]

Figure 7. Midwest ISO State of the Market Report Illustration of Fuel Type of Price Setting (Marginal) Units in MISO



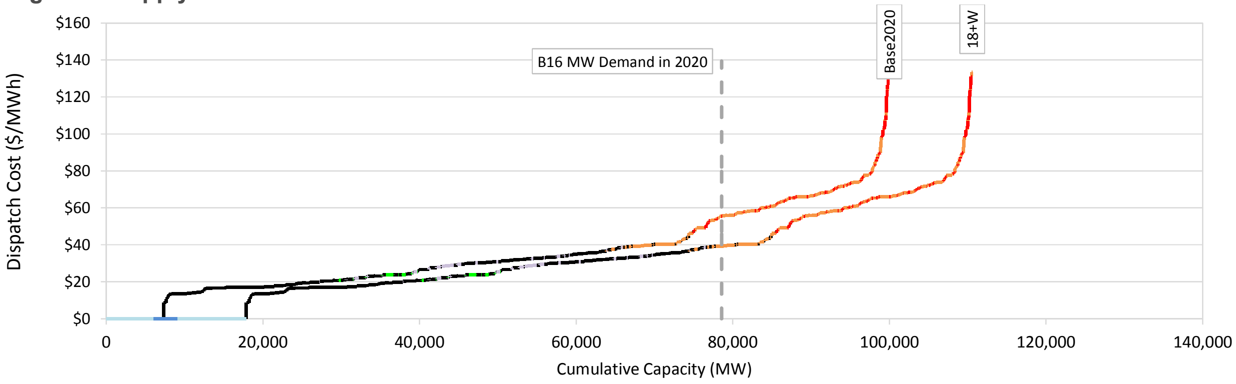
Source: Midwest ISO, 2010 State of the Market Report, page 6, Figure 5.

Figure 8 below illustrates the manner in which additional supply leads to a price effect in the Midwest energy market. It shows two MISO-system supply curves: one based on a set of existing resources ("Base 2020," the upper, to-the-left curve in the figure), and one based on a set of existing resources plus the effect of an additional 18 GW of installed wind capacity ("18+ GW," the lower, to-the-right curve in the figure).

The data that make up the system supply curves shown in Figure 8 were developed by Synapse based on: supply resource information available for the MISO system; assumptions used by Synapse for natural gas, oil, and coal prices; and other supply attributes such as wind resource output and outage assumptions.

60 MISO 2010 State of the Market Report, page 7. "In addition, sustained growth in wind output shifted the energy supply curve (lowering overall supply costs). This shift displaced higher-cost generation, including combined-cycle and less efficient coal-fired generation. As a result, coal-fired units were more frequently on the margin."

Figure 8. Supply-Induced Price Effect Illustration – MISO Market Area - for 2020



Source: Synapse. Note: blue = wind, black=coal, orange/red=gas/oil.

In this illustration, the 18 GW of installed wind is providing 10.6 GW of total system supply, representing an average aggregate output of 59% of the installed capacity for this particularly high-output block of time[61.] The effect of the aggregate wind resource supply is to shift the system supply curve to the right, all else equal (i.e., no other additions or retirements). This shift leads to a clearing price at the intersection of supply and demand that is relatively lower for the system supply curve that includes the 18 GW of additional installed wind. The result is shown for a single demand block, in this case the B16 block. As shown in the figure, the clearing price differential is roughly $13/MWh.

The actual differential price effect associated with any two system supply curves depends on a myriad of factors, some of which can be difficult to predict. Essentially, the difference depends on all the factors that make up construction of a system supply curve at any point in time. A system supply curve or dispatch curve is an ordering of resource blocks, from lowest short-run marginal cost to highest short-run cost. The key factors that make up the system supply curve construction for any given interval include the following:

- The net effect of non-wind resource additions and retirements;
- The effect of plant outages, planned and forced, full and partial;
- Fuel prices, especially for the resources that use the primary marginal fuels, natural gas and coal;
- The assumed heat rate for thermal resources;
- The assumed variable operation and maintenance costs; and
- The average output of wind resources.

The system supply curve for MISO includes resources that are located in the western, central, and eastern sub-regions of MISO. At any given time, there could be transmission limitations that create

[61] As will be seen, annual average wind capacity factors – or average output – for the MISO region is modeled at roughly 35%. Some blocks – for example, during summer periods – are modeled with relatively low output (e.g., 20%) and other blocks (e.g., some shoulder and winter periods) are modeled with higher relative output. In all cases, the values are aggregate resource output for all wind addition modeled in the MISO region.

congestion in the marketplace, effectively causing the system supply curve to split, and different clearing prices to be seen in different regions of the marketplace. To the extent that wind supply resources are concentrated in the western region, the supply-induced price effect (SIPE) would be magnified in this region, and reduced in the eastern and central regions. Since more of the load is located in the central and eastern regions of MISO (compared to the western region), the overall beneficial effect on load of the SIPE would be diluted during times of congestion. However, two factors must be considered concerning this potential dilution of the benefit to load of the SIPE: 1) the west-to-east congestion effect would be mitigated with additional transmission construction across the MISO sub-regions, and 2) more wind output occurs during non-peak periods in the MISO region than during peak periods, in general. If summer peaking periods are the time of greatest financial effects from congestion[62], they are also the time of lowest average wind output. Thus, while the capacity value of wind might be gauged lower due to concern over sustained output during summer peak conditions, the SIPE benefits will tend to be concentrated during non-summer peak periods.

C. Spreadsheet Model and Key Input Assumptions

Description

Synapse developed an Excel spreadsheet model to analyze the supply-induced price effect seen in structured, clearing price markets such as MISO. The model was designed to be a flexible tool for gauging broad supply-induced price effect patterns associated with different scenarios of resource supply and load in the MISO region. It is not designed to predict the relative levels of resource types likely to be on the MISO grid in 2020 and 2030. A key attribute of the model is its ability to test many scenarios of resource supply, and illuminate developing patterns of market price movements associated with the particular drivers of electricity prices in the MISO region, namely the makeup of supply resources, retirement patterns, fuel price patterns, and load. The model's strength is not in any ability to accurately gauge absolute price patterns in the market, but instead to gauge relative energy market price effects given long-term resource alternatives.

The model is purposefully a simplified representation of the MISO region, and is designed to analyze patterns of supply-induced price effects given a wide range of input assumptions. The model's core characteristics are as follows:

Single energy zone. The model's focus is to assess the price effects of large-scale wind integration across the broader Midwest region. In particular, the effects we test are relative—i.e., price differences given two different scenarios of supply resource deployment. We reasonably assume that a significant increase in transmission infrastructure would accompany any large-scale integration of wind in the Midwest region. Increased transmission not only serves to enable interconnection, injection, and transport of increased wind resources, it can serve to reduce some—or much—of the transmission congestion associated with west-to-east transfers of energy

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[62] In later years, 2020 and 2030, a Midwest region supply base that is more flexible than today's coal-dominated resource base could be expected to exhibit less congestion during off-peak hours than is sometimes the case today, when minimum run requirements for less-flexible units cause congestion to arise from the presence of significant amounts of wind.

in the MISO region.[63] For the purposes of this modeling exercise, we have assumed a single energy zone, encompassing the entire MISO region.

Supply curve resource data. We use ProSym input data for existing MISO region supply resources. For new resources, we define our own scenarios that add wind, gas-fired GT and/or gas-fired CC units, and retire regional coal resources. In all scenarios, we maintain sufficient resource adequacy by ensuring a peak load / capacity balance that meets at least minimum planning reserve margins for the region.

Outage assumptions. We use a planned outage assumption of 8% for all non-wind resources, and we spread these outages out across "shoulder season" (i.e., spring and fall) load blocks.[64] We use forced outage data from our ProSym data set to define "derated" net capacity values for all non-wind supply resources. Wind resource output values use aggregate average capacity values by load block and by MISO sub-region.

MISO region peak load projection. We use the MISO region peak load projection, as reported in MTEP 2011 and in the NERC 2011 LTRA.

20 load blocks per year. Load patterns vary daily and seasonally, but with a large degree of predictability, within certain error bounds. Conventional supply resources can be economically dispatched to meet these patterns. Wind resources are not dispatchable, but average aggregate output of MISO regional and sub-regional wind resources can be reasonably estimated and mapped to periods corresponding to the defined load blocks.[65] We define 20 load blocks per year, across each of summer, winter, and shoulder seasons. These blocks capture the broad patterns of supply and demand. Each block is modeled as a fraction of the highest peak demand projected for the MISO region. The load block definition allows us to capture the price effects during "peaky" periods, and to discern wind output differences that exist between day and night, and between winter, summer, and spring and fall. The block representation allows us to assign planned outage periods to shoulder seasons. Table 7 below summarizes the load block structure we use.

[63] A more flexible operating resource base (e.g., less low-ramp-rate coal steam, more high-ramp-rate gas turbines and/or combined cycle units) will also help to reduce some of the congestion that arises because of minimum output requirements currently in place for part of the less-flexible coal fleet.
[64] MISO SOM 2010 includes aggregate resource data that indicates planned outages in 2010 were 8.1%.
[65] For the purposes of our model, we use the NREL-based wind output blocks as defined in the EIPC planning process.

Table 7. Load block structure

Season	Duration (Hours)	Block ID	Ratio of Block Load to Peak Load	Season	Duration (Hours)	Block ID	Ratio of Block Load to Peak Load
Summer	10	B1	1	**Shoulder**	25	B11	0.685
	25	B2	0.988		200	B12	0.645
	75	B3	0.92		600	B13	0.622
	100	B4	0.861		900	B14	0.579
	200	B5	0.819		1203	B15	0.492
	300	B6	0.763	**Winter**	25	B16	0.786
	400	B7	0.71		100	B17	0.716
	500	B8	0.649		400	B18	0.677
	800	B9	0.588		700	B19	0.626
	1262	B10	0.5		935	B20	0.518

Source: Synapse, using the same load block structure as was modeled in the EIPC process.

Notably, we are using the same temporal block structure that was used in the EIPC process, which is assessing transmission needs in the Eastern Interconnection.[66] We do this for two reasons: first, the simplified structure lends flexibility to the model, as we are able to quickly run scenarios with different input assumptions. Models that use hourly granularity (i.e., 8,760 hourly blocks to represent the year) are more complex and take longer to execute. Second, perhaps more importantly, the EIPC process uses publicly available input assumptions[67] that include MISO sub-regional breakdowns of wind capacity factor by load block for NREL wind data. This allows us to generate system supply curves in each of the 20 load block intervals that capture, on average and in aggregate across MISO, the daily and seasonal variability of wind output for the purpose of estimating its effect on energy market clearing prices.

20 wind output blocks per year. For each of the 20 load blocks we use to define our energy market for the year, we are able to map the aggregate wind output from Midwest wind resources to each block, based on NREL data compiled and used publicly in the EIPC process. We build on this database in our assessment of supply-induced price effects. The table below contains our baseline input assumptions for wind output blocks in the MISO region. The table below illustrates that our model uses a particular level of aggregate wind output to represent wind capacity in our system supply curve. For any given block, we construct the system supply curve using the capacity of supply resources. For wind, this capacity level is the installed capacity value multiplied by the applicable block capacity factor. For fossil resources, the output level accounts for planned outages (assumed to occur in shoulder seasons) and an average annual "derate" that represents forced outage rates.

[66] Reports, modeling results, and related material are available on the EIPC website at www.eipconline.com.
[67] See for example the some of the extensive documentation and input data available at http://www.eipconline.com/Resource_Library.html.

Table 8. Wind supply shapes – Average annual capacity factor

Block	Hours of Year	Pcntg. of hours	Sub-Region	MISO_IN	MISO_MI	MISO_MO-IL	MISO_W	MISO_WUMS
B1	10	0.1%	B1	41%	63%	41%	28%	59%
B2	25	0.3%	B2	30%	46%	32%	35%	40%
B3	75	0.9%	B3	26%	24%	23%	27%	23%
B4	100	1.1%	B4	19%	21%	19%	27%	20%
B5	200	2.3%	B5	21%	21%	20%	25%	20%
B6	300	3.4%	B6	21%	20%	22%	24%	21%
B7	400	4.6%	B7	21%	20%	23%	30%	22%
B8	500	5.7%	B8	22%	20%	25%	35%	25%
B9	800	9.1%	B9	25%	23%	27%	35%	27%
B10	1262	14.4%	B10	26%	24%	29%	39%	30%
B11	25	0.3%	B11	44%	30%	53%	28%	31%
B12	200	2.3%	B12	37%	29%	40%	36%	32%
B13	600	6.8%	B13	34%	29%	36%	37%	30%
B14	900	10.3%	B14	35%	31%	37%	40%	33%
B15	1203	13.7%	B15	38%	32%	41%	41%	38%
B16	25	0.3%	B16	59%	64%	59%	56%	67%
B17	100	1.1%	B17	39%	44%	44%	51%	46%
B18	400	4.6%	B18	42%	47%	42%	42%	41%
B19	700	8.0%	B19	42%	44%	41%	39%	38%
B20	935	10.7%	B20	48%	43%	49%	42%	43%
Annual Avg.:				33%	30%	35%	38%	33%

Uniform energy market clearing price. For each block, we “clear the market” by using the applicable system supply curve—which incorporates average wind output that respects the seasonal and diurnal variability associated with wind resources—and an associated load value for that block.

Data Sources

We use the following data sources for our model:

- Supply resources: PROSYM data set, filtered for the existing MISO region.
- Peak load estimate: MISO MTEP 2011, total internal demand.
- Load blocks: each block is modified from the peak load. The block load shapes are taken from the standard EIPC load block inputs.
- Sensitivities: Synapse-defined sensitivities include varying amounts of wind resource additions, coal plant retirements, and gas-fired plant additions.
- Transmission assumptions: We rely on MISO data on revenue requirements for transmission for the MVP portfolio. We use the same methodology as used by MISO for the MVP portfolio to determine transmission rate effects associated with increased levels of transmission. We use a range of values from the “indicative transmission” section of the RGOS report to determine potential transmission costs for future scenarios of wind integration.

D. Results of Supply-Induced Price Effect Analysis

This section contains and describes the results of our supply-induced price effect (SIPE) analyses. The results illustrate the way in which energy market prices would change, relative to a baseline price, with the addition of more wind power. The baseline price is generally indicative of a scenario of no additional wind supply beyond what is currently in place. We analyze baseline scenarios that assume minimal (3 GW), moderate (12 GW), and aggressive (23 GW) levels of coal retirement, coupled with gas turbine and combined cycle additions to maintain a reasonable planning reserve.

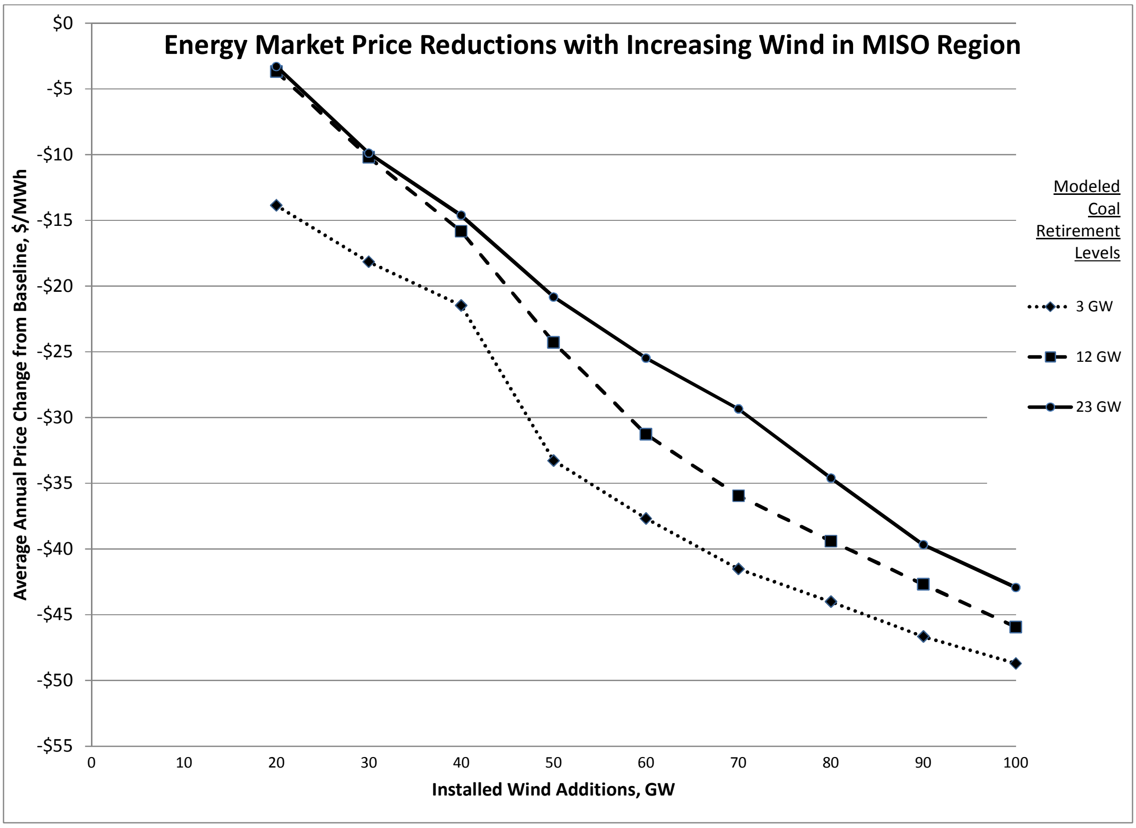
By comparing across scenarios, we are able to discern the incremental SIPE effect, such as the effect when additional wind is added on top of the roughly 18 GW of wind required to meet RPS standards in MISO states. In all cases, the price effect is an average annual effect, based on the 20-block model we've described. The clearing prices have been computed for each block, and then weighted according to the duration of the block for the year. The results include modeling of two years: the medium-term time frame, 2020, and the long-term time frame, 2030. The results are presented under different assumptions for two critical variables, namely:

- The level of wind supply;
- The level of non-wind resource additions and retirements.

Following the presentation of our results, we further discuss and interpret our findings.

Figure 9 below contains our initial set of SIPE results, which illustrate the broad pattern of prospective changes to MISO region market prices as wind resources are installed throughout the region. It is intended to show trends—not to predict absolute price movements. The graph indicates that energy market price reductions stem from the net effect of additional infra-marginal wind resources (i.e., wind resources that have marginal costs less than the market clearing price), and retirements and additions of conventional fossil-fuel generation. This net effect leads to changes in the MISO-region system supply curve shape and makeup, and lower clearing prices in the energy market.

Figure 9. Supply-Induced Price Effect Differences from Baseline – Trend Lines



The figure above reveals the following:

1. For each of three different retirement sensitivities (modeled coal retirements of 3 GW, 12 GW, or 23 GW), we compute the price effect for nine different scenarios of wind resource addition to the MISO region—increments starting with a 20 GW increment, then a 30 GW increment, etc. up to a 100 GW increment. There is roughly 10 GW in place in MISO now—thus the first of nine increments brings the total amount of wind to 30 GW, the next increment increases it to 40 GW, etc. up to a total system wind of 110 GW. We chose 20 GW as our first increment to reflect a total system wind of 30 GW, in line with MISO's "business as usual, mid-low demand scenario" as described in the MTEP 2011 report.

2. As more wind is modeled on the system, the energy market clearing prices are reduced relative to the baseline case of 10 GW of wind. For example, as seen for the initial sensitivity case of 3 GW of coal retirement, the supply-induced price effect for the first increment of wind (bringing the total to 30 GW, modeled as in place by 2020) is roughly $14/MWh. At 50 GW of additional wind (which we model as being available by 2030), the price effect reaches roughly $33/MWh. In other words, energy market clearing prices would be roughly $33/MWh lower, on average, in 2030 if 50 GW of additional wind (beyond the existing 10 GW) is added to MISO's system.

3. To examine incremental SIPE effects, between one level of wind additions and another level, one can move up the curve between points. For example, moving between 20 GW and 40 GW of additional wind for the base sensitivity (3 GW of coal plant retirement, 2020) the incremental price effect is $7.61/MWh (21.47 minus 13.86, as seen in Table 9 below).
4. The incremental transmission rate increase associated with each of three levels of transmission build-out is generally lower than the price reductions shown on the graph. At the low end of the range, the rate effect associated with the MVP portfolio, alone, averages roughly $1/MWh by 2015. At the high end of the range, the rate impact associated with the MVP portfolio plus Synapse's High T Expansion scenario in 2031 is $11.2/MWh (1.12 cents/kWh). This is significantly lower than the energy market price reductions seen in Figure 9.

Table 9 below presents the data from Figure 9, and also contains key assumptions associated with the supply resources used in the model to develop the energy market supply curves, which in turn were used to gauge the supply-induced price effects.

In particular, Table 9 shows the levels of resource retirement and additions assumed. In general, our aim was to assess the individual effect of the wind additions on market prices. The model did not attempt to optimize resource expansion. We maintained at least minimum levels of planning reserve for each scenario analyzed.

Table 9. SIPE Results and Key Supply Resource Expansion/Retirement Assumptions

Case	Base Year Modeled	Wind Additions GW	Gas CT Additions GW	Gas CC Additions GW	Coal Retired GW	Block-Weighted Average Annual Price, $/MWh	MISO Peak Load, MW	Estimated Capacity Reserve Margin	Energy Price Delta, from Base Year Price, $/MWh
3 GW Coal Retirement									
Base2020	2020	0	10	0	-3	58.47	99,929	18.6%	0
Base2030	2030	0	15	0	-3	75.35	105,562	16.3%	0
20 GW Wind	2020	20	10	0	-3	44.61	99,929	23.7%	13.86
30 GW Wind	2020	30	10	0	-3	40.31	99,929	26.3%	18.16
40 GW Wind	2020	40	10	0	-3	37	99,929	28.9%	21.47
50 GW Wind	2030	50	15	0	-3	42.07	105,562	28.5%	33.28
60 GW Wind	2030	60	15	0	-3	37.67	105,562	30.9%	37.68
70 GW Wind	2030	70	15	0	-3	33.83	105,562	33.4%	41.52
80 GW Wind	2030	80	15	0	-3	31.34	105,562	35.8%	44.01
90 GW Wind	2030	90	15	0	-3	28.69	105,562	38.2%	46.66
100 GW Wind	2030	100	15	0	-3	26.64	105,562	40.7%	48.71
12 GW Coal Retirement									
Base2020	2020	0	10	10	-12	57.83	99,929	19.5%	0
Base2030	2030	0	15	10	-12	75.09	105,562	16.9%	0
20 GW Wind	2020	20	10	0	-12	54.15	99,929	15.9%	3.68
30 GW Wind	2020	30	10	0	-12	47.63	99,929	18.5%	10.2
40 GW Wind	2020	40	10	0	-12	42	99,929	21.1%	15.83
50 GW Wind	2030	50	15	0	-12	50.8	105,562	20.9%	24.29
60 GW Wind	2030	60	15	0	-12	43.81	105,562	23.3%	31.28
70 GW Wind	2030	70	15	0	-12	39.14	105,562	25.8%	35.95
80 GW Wind	2030	80	15	0	-12	35.69	105,562	28.2%	39.4
90 GW Wind	2030	90	15	0	-12	32.41	105,562	30.6%	42.68
100 GW Wind	2030	100	15	0	-12	29.16	105,562	33.1%	45.93
23 GW Coal Retirement									
Base2020	2020	0	15	20	-23	58.55	99,929	22.8%	0
Base2030	2030	0	20	20	-23	75.15	105,562	20.6%	0
20 GW Wind	2020	20	15	10	-23	55.25	99,929	19.3%	3.3
30 GW Wind	2020	30	15	10	-23	48.66	99,929	21.8%	9.89
40 GW Wind	2020	40	15	10	-23	43.93	99,929	24.4%	14.62
50 GW Wind	2030	50	20	10	-23	54.31	105,562	24.5%	20.84
60 GW Wind	2030	60	20	10	-23	49.67	105,562	27.0%	25.48
70 GW Wind	2030	70	20	10	-23	45.8	105,562	29.4%	29.35
80 GW Wind	2030	80	20	10	-23	40.54	105,562	31.8%	34.61
90 GW Wind	2030	90	20	10	-23	35.47	105,562	34.3%	39.68
100 GW Wind	2030	100	20	10	-23	32.22	105,562	36.7%	42.93

E. Discussion and Interpretation of Results

One effect of introducing greater levels of wind resources into the Midwest market region (modeled as the MISO region) is to generally depress the average annual market price from that which would otherwise be seen, based on the standard clearing price algorithm used in structured markets such as the Midwest ISO. Our sensitivity analyses across different coal plant retirement scenarios, and different levels of wind installation, reveal average annual energy market price differences that exceed the incremental costs associated with new transmission required to integrate greater levels of wind energy.

One of our benchmark scenarios looks at the likely effect in 2020 with 3 GW of coal retired in MISO, for three different levels of wind additions: 20, 30 and 40 GW. For these scenarios, energy market price differences of $14, $18, and $21/MWh are seen. This means that market price suppression effects from wind energy could far exceed the average rate effect associated with the MVP portfolio and each of the Synapse transmission expansion scenarios, as well as the *total* average transmission rate associated with each scenario. (The total rate includes all transmission rate cost components, including the cost of existing transmission and expected MISO reliability projects.) The incremental and total transmission rates associated with each transmission expansion scenario are shown in Table 10, below. This table presents a subset of the information in Table 6.

Table 10. Incremental and Total Transmission Rates Associated with Transmission Expansion Scenarios

Transmission Scenario - Cost Basis	Transmission Rate Impact of Scenario Listed, $/MWh			Total Average Transmission Rate, $/MWh		
	2015	2021	2031	2015	2021	2031
Current MVP Only	1.02	1.64	1.28	7.84	8.15	5.85
Current MVP + Synapse Low T Expansion	1.02	4.85	6.52	7.84	11.36	11.09
Current MVP + Synapse Medium T Expansion	1.65	5.93	8.46	8.51	12.44	13.03
Current MVP + Synapse High T Expansion	1.76	6.40	11.20	8.58	12.90	15.77

The results of this analysis also illustrated rough temporal patterns; for periods when load is relatively high and wind output is relatively low (e.g., summer high load hours), we found the price effect is diminished, and in a number of scenarios, negative. Conversely, the greatest price effect is seen in shoulder and winter hours, when aggregate wind plant output is expected to be highest.

The key driving factors in the model include natural gas prices, level of coal plant retirement, level of gas plant addition, and the presumption that MVP portfolio and other transmission project build-outs occur on a schedule commensurate with the increases in wind resources suggested by the scenarios. Other important factors include the "wind shapes" (supply output at different points in time), the average wind capacity factors assumed, the plant outage rates for all power plants, and the load level.

These initial results do not discern the extent to which MISO market-wide price depression arising from increased use of wind resources will directly "flow through" to load-serving entities in the region in 2020, or in 2030. Generally, the rates seen by consumers for electricity depend on the blended prices associated with a portfolio of power supplies, in some cases pursuant to vertically-integrated utility supply provision or procurement policies, in other cases based on merchant supply prices, and at times based on a mix of these procurement arrangements. Regardless of these differences, all consumers will be affected by the key marginal driving factors that exist now: likely costs of coal plant retrofit, coal retirement decisions, cost of power from existing and new gas facilities, and the impacts of wind resources on market prices. The pace of effect that these factors will have on individual MISO-region customers will depend on the decisions taken by regulatory commissions and legislative initiatives. Much of the price effect patterns seen here will eventually find their way to ratepayers in the MISO region.

To translate the market price impact into projected power supply cost savings for MISO region customers, we use a simple approach: the market price impact is a proxy for power supply cost savings that accrue to at least a portion of the portfolio of supply that serves MISO region customers. At the low end of our assessment, we assume that 50% of the power supplies purchased will be at the proxy MISO market price. At the high end of our range, we assume the MISO market price is a full proxy (100%) for the costs of power in future years. Based on this range, we compute the total MISO market region power supply savings for two increments of wind additions – 20 GW, and 40 GW, in place by 2020. Table 11 contains the results of that exercise, and illustrates that power supply cost savings for MISO-region customers could range from $3.9 billion to $7.9 billion per year lower than baseline costs for the 20 GW wind addition, and from $6.1 to $12.2 billion per year lower than baseline costs for the 40 GW wind addition.[68] These cost savings will far exceed the annual costs of any transmission improvements needed to integrate this level of wind addition, as seen in the table.

We can also gauge the effect on an "average" residential customer, using 1,000 kWh per month of electricity. For the 20 GW wind addition, this average customer could see total power supply savings of $83 to $166 per year; for the 40 GW wind addition the savings range is $129 to $258 per year. Net of transmission costs, this customer would save between $63 and $147 per year (20 GW wind addition), and $71 to $200 per year for the 40 GW wind addition scenario.

Table 11. Annual Power Supply Savings from Supply Induced Price Effect, 2020, for 20 GW and 40 GW Wind Addition Scenarios, MISO Market Region

% of power procured at MISO market proxy price	50%	75%	100%
20 GW Wind Addition			
Price Effect, $/MWh	$13.86/MWh		
Applicable Load, GWh	284,235	426,352	568,470
Annual Gross Savings, $ Billions	$3.9	$5.9	$7.9
Annual Transmission Costs (MVP) $ Billions	$0.9	$0.9	$0.9
Annual Net Savings, $ Billions	$3.0	$5.0	$6.9
40 GW Wind Addition			
Price Effect, $/MWh	$21.47/MWh		
Applicable Load, GWh	284,235	426,352	568,470
Annual Gross Savings, $ Billions	$6.1	$9.2	$12.2
Annual Trans. Costs (MVP+Scen. I) $ Billions	$2.8	$2.8	$2.8
Annual Net Savings, $ Billions	$3.3	$6.4	$9.4

[68] The lower value reflects a future year assumption that MISO market price is a proxy for supply costs for 50% of regional power supply, and the upper value assumes that the market price is a full (100%) proxy for the costs to load.

4. Conclusions & Next Steps

In sum, this study indicates that adding more wind power to the grid in MISO, above and beyond what will be enabled by the MVP portfolio, would result in the continual decline of energy market prices and lead to lower electric rates for ratepayers (relative to rates in a less windy electrical landscape)—even when you factor in the costs of additional transmission.

The table below shows that the price savings associated with the wind additions modeled by Synapse exceed not only the incremental rate effect associated with each of the studied transmission expansion scenarios, but also, in many cases, the *total* transmission rate associated with each scenario. (The total rate includes all transmission rate cost components, including costs for existing transmission and expected MISO reliability projects.)

Table 12. Total Average Transmission Rates Associated with Synapse Expansion Scenarios, and Corresponding SIPE from Transmission-Enabled Wind

Transmission Scenario - Cost Basis	Approximate Range of MISO Region Wind Enabled by Scenario, GW	Total Average Transmission Rate, $/MWh			Range of Energy Price Reduction from SIPE Model, $/MWh
		2015	2021	2031	
Current MVP Only	20-30	7.8	8.1	5.8	3-10
Current MVP + Synapse Low T Expansion	30-50	7.8	11.4	11.1	10-33
Current MVP + Synapse Medium T Expansion	>50	8.5	12.4	13.0	>21
Current MVP + Synapse High T Expansion	>70	8.6	12.9	15.8	>29

We draw the following conclusions from our analysis:

- Ongoing installation of wind energy across the MISO grid over the next two decades will continually and inexorably put downward price pressure on market energy prices. The price suppression effect will be material, and will be pervasive.
- Anticipating that any level of wind increase and coal retirement scenario will still lead to sufficient capacity reserves on the grid, the price effect is seen to persist and be material under a range of coal retirement / gas addition circumstances.
- If gas prices rise above the Energy Information Administration's current Annual Energy Outlook real price projections for 2020 and 2030, the price suppression effect from wind will be greater. Similarly, this effect will be magnified under scenarios with large coal retirement, since gas-fired generation is likely to be on the margin for a greater share of market-price-setting intervals.
- Transmission increases that accompany wind additions will continue to minimize price differentials across the region (i.e., lower congestion costs) and allow the presence of wind energy to affect clearing prices throughout the MISO region.

- To the extent that transmission additions allow for capture of the highest valued wind resources, lower total investment in wind capacity will be required to achieve the effects seen in this analysis.

The next steps we see to expand this analysis and more carefully assess the interrelationship of Midwest region wind and transmission are as follows:

- Continue to analyze different sensitivities with the existing model structure. In particular, examine wind performance changes, gas price changes, and differing levels of coal plant retirement.
- Conduct a production cost and resource expansion analysis that considers a more formally optimal resource expansion path given specific levels of coal plant retirement in the region, and given policies on carbon emissions and renewable portfolio standards post-2026.[69]
- Incorporate MISO's neighboring regions in the analysis. In particular, model import and export effects that will be seen, especially given the existing connections and the possible expansion of extra-high-voltage interconnections to the Southwest Power Pool, PJM, and the regions immediately west of MISO's boundaries. Incorporate the effects of likely increased coordination between markets and system operators.
- Incorporate the effects of aggressive demand-side measures in assessing future loads and the need for any particular level of resource expansion.
- More carefully analyze the "flexibility" need and supply resource projections of the region, and how this will affect transmission expansion needs.

[69] MISO accounted for the current end dates of regional state RPS polices, which is 2026.