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April 9, 2013

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Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: Supplement to Certificate of Need Filing
***In the Matter of the Application of ITC Midwest for a Certificate of Need for the Minnesota-Iowa 345 kV Transmission Project in Jackson, Martin, and Faribault Counties*, Docket No. ET6675/CN-12-1053**

Dear Dr. Haar:

ITC Midwest hereby submits the enclosed Supplement to its Application for a Certificate of Need for its Minnesota - Iowa 345 kV Transmission Project, which was filed March 22, 2013. This supplement consists of the following:

- a new Appendix N, which contains an analysis of the locational marginal price impacts of Midwest Independent System Operator, Inc.'s Multi-Value Project ("MVP") 3, and a production cost analysis of MVP 3 and MVP 4;

- a revised List of Appendices to be substituted for the current list on page vi of the Application's Table of Contents, updated to include Appendix N; and

- a revised Appendix Table of Contents to be substituted for the current table of contents after the "Appendix TOC" tab, updated to include Appendix N.

The new and revised pages are marked in accordance with Minnesota Rule 7849.0200, subpart 3, governing changes to a Certificate of Need Application.

Copies of this Supplement are being provided to all those who received a copy of the original Certificate of Need Application, as shown on the enclosed distribution list. Copies of the Supplement have also been served on all persons on the docket service list who did not receive a copy of the Application, who are identified on the distribution list by an asterisk.

If you have any questions about this filing, please do not hesitate to contact me.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Cc: Attached distribution list

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis

Rodney Frame
Todd Schatzki
Pavel Darling

Analysis Group

April 2013

(Revised April 9, 2013)

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis

Rodney Frame
Todd Schatzki
Pavel Darling

Executive Summary

ITC Midwest LLC (ITC Midwest) is proposing to develop the Minnesota – Iowa 345 kV Transmission Project (the Project). The Project involves construction of new 345 kV transmission lines and associated facilities in Minnesota and Iowa with the purpose of providing economic, policy and reliability benefits. The Project is part of MVP 3, one of the 17 projects that make up the Midwest Independent Transmission System Operator, Inc. (MISO) Multi-Value Project (MVP) Portfolio.

Using the PROMOD market simulation model, the analyses herein estimate the change in locational marginal prices (LMPs) in Minnesota from implementing the Project and other components of MVPs 3 and 4. MVP 4 interconnects to MVP 3 at a substation in Kossuth County, Iowa. This Supplemental Report provides results based on wind curtailment estimates developed by ITC Midwest. Our prior report (Initial Report) relied on wind curtailment estimates developed by MISO for MVPs 3 and 4 combined. ITC Midwest developed its wind curtailment estimates to allow additional analysis of the impacts of MVP 3 alone, because MISO had not examined the impacts of the two interconnected projects individually. As well, this Supplemental Report contains estimates of annual production cost changes associated with the addition of MVP 3 alone and MVPs 3 and 4 combined.

Using ITC Midwest's wind curtailment estimates, with development of MVPs 3 and 4, average LMPs for Minnesota fall by $0.48 per MWh (1.7%) in 2021 and $0.68 per MWh (2.1%) in 2026 under Business As Usual: Low Demand market conditions. Under Business As Usual: High Demand market conditions, price reductions are similar: $0.52 per MWh (1.5%) in 2021 and $0.56 per MWh (1.2%) in 2026. These LMP changes result in annual reductions in wholesale energy payments for Minnesota load that range from $36.1 million (2021 Business As Usual: Low Demand) to $52.5 million (2026 Business As Usual: Low Demand).

Development of MVP 3 alone, without development of MVP 4, results in smaller LMP reductions. In 2021, LMPs fall by $0.06 per MWh (0.2%) under Business As Usual: Low Demand market conditions, and $0.05 per MWh (0.2%) under Business As Usual: High Demand market conditions. In 2026, LMPs are effectively unchanged. These LMP changes result in annual reductions in wholesale energy payments for Minnesota load that range from $0.2 million (2026 Business as Usual: High Demand) to $4.6 million (2021 Business as Usual: Low Demand).

LMP reductions from the implementation of MVPs 3 and 4 are also estimated to be widespread across the eight individual load-serving entities (LSEs) in Minnesota included in the PROMOD analysis. Average LMPs decline for all eight LSEs in 2021 and for seven of the eight LSEs in 2026. LMP reductions from the implementation of MVP 3 are varied, with LMPs rising in some regions and falling in others.

Development of MVPs 3 and 4 also lowers production costs needed to meet load across MISO. In 2021, with MVPs 3 and 4, production costs fall by $114.9 million under Business As Usual: Low Demand conditions, and $132.2 million under Business As Usual: High Demand conditions. Development of MVP 3 alone reduces production costs in 2021 by $42.9 million under Business As Usual: Low Demand conditions, and $49.5 million under Business As Usual: High Demand conditions. Reductions in production costs in 2026 are comparable on a percentage basis.

(Revised April 9, 2013)

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis

Rodney Frame
Todd Schatzki
Pavel Darling

1. BACKGROUND ON THE MINNESOTA-IOWA PROJECT

ITC Midwest LLC (ITC Midwest) is proposing to construct new 345 kV transmission lines and associated facilities with the purpose of providing economic, policy and reliability benefits. This project, the Minnesota – Iowa 345 kV Transmission Project (the Project), is being developed as part of the Midwest Independent Transmission System Operator, Inc.'s (MISO) 17 Multi-Value Project (MVP) portfolio. MVPs are transmission projects in the MISO footprint that have been "determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones."[1] The costs of MVPs are recovered from all load within and exports from MISO via a per MWh charge.[2]

Among other things, the portfolio of MVPs is intended to help enable the reliable delivery of renewable energy, including wind power, within the MISO footprint, allow for a more efficient dispatch of generation resources, open markets to further competition and spread the benefits of low-cost

[1] Federal Energy Regulatory Commission, Order, Docket No. ER10-1791-00, December 16, 2010 Order (133 FERC ¶ 61,221), at Para 1. See also the listing of the three MVP criteria in Section II.C.2 of Attachment FF of the MISO Tariff, as follows:
Criterion 1. A Multi Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

Criterion 2. A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher ….

Criterion 3. A Multi Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs ….

[2] See MISO Tariff, Schedule 26A, Multi-Value Project Usage Rate, and Attachment MM, Multi-Value Project Charge.

generation. The Federal Energy Regulatory Commission (FERC) approved the methodology used by MISO to identify the MVP portfolio as "an important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or growing loads."[3]

MISO's *Multi Value Project Portfolio, Results and Analysis*, January 10, 2012 (MISO MVP Report) provides a comprehensive assessment of the complete 17 MVP portfolio and recommends that each of the 17 projects be approved by MISO's Board of Directors for inclusion in Appendix A of the MISO Transmission Expansion Plan process and implemented. On December 8, 2011, the MISO Board approved this recommendation.

The Project consists of a 345 kV transmission line and associated facilities located in Jackson, Martin, and Faribault counties in Minnesota, and Kossuth County in Iowa.[4] The Project, together with other facilities being proposed by MidAmerican to be constructed in Iowa [5] comprises what is referred to as MVP 3 in MISO's MVP portfolio. The development of MVP 3 is closely tied to MVP 4, which is also being proposed by ITC Midwest and MidAmerican.[6] Together, MVPs 3 and 4 provide new pathways to help power flow from western Minnesota and Iowa, connecting to major 345 kV hubs in eastern Iowa, along with providing reliability and congestion relief benefits.

2. METHODOLOGY

The analyses described herein use the PROMOD IV (PROMOD) market simulation model to estimate both wholesale electricity price and annual production cost changes resulting from MVPs 3 and 4. PROMOD, which is marketed by Ventyx, simulates the operation of the regional generation and transmission system, in so doing reflecting a variety of generator operating characteristics and constraints,

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[3] Midwest Indep. Transmission Sys. Operator, Inc., 133 FERC ¶ 61,221 at Para 3 (Dec. 16, 2010 Order).

[4] In Minnesota, ITC Midwest's existing Lakefield Junction Substation will be expanded for a new 345 kV line to be constructed between the substation and a new Huntley Substation, proposed to be located south of the existing Winnebago Junction Substation. The Winnebago Junction Substation will be removed and the four existing 161 kV lines connecting to Winnebago Junction will be re-connected to the Huntley Substation. From Huntley, the 345 kV transmission line will run south to cross the Minnesota/Iowa border and connect first to a new ITC Midwest Ledyard Substation, and then to a new Kossuth County Substation owned by MidAmerican Energy Company ("MidAmerican"), both in Kossuth County, Iowa. Details on the route taken by the Project, and new and modified changes to substations and transformers, are provided in Section 2.3 of Chapter 2, Project Description and Regulatory Overview. The expected total cost of the Project is approximately $271 to $283 million (plus or minus 30 percent.) Chapter 2, Project Description and Regulatory Overview.

[5] As a part of MVP 3, MidAmerican is proposing to (1) construct a 345 kV connection that runs from the Kossuth County Substation south to its existing Webster Substation, near Fort Dodge, Iowa, and (2) construct a 345 kV line running west from the Kossuth County Substation to its new O'Brien Substation, near Sanborn, Iowa.

[6] MVP 4 includes new transmission infrastructure that runs across Iowa through Winco, Lime Creek, Emery, Blackhawk and Hazleton substations.

and transmission system topology and limits. Among other things, PROMOD allows the estimation of time-varying LMPs[7] under different sets of operating conditions and infrastructure development. PROMOD also allows the estimation of generator-by-generator variable production costs. The PROMOD analysis and the data set employed are described more fully in Appendix A. The PROMOD market simulation model and the data set employed largely are identical to those used by MISO in the MISO MVP Report assessing the 17 projects in the MVP portfolio package.

The hour-by-hour LMP values produced by the PROMOD analysis were used, along with the amount of load served from each of the pricing nodes, to develop load-weighted average wholesale energy prices. These load weighted prices were determined for Minnesota taken as a whole and for each of the eight individual Minnesota load-serving entities (LSEs) that are represented in the PROMOD database.[8] Appendix A provides further detail on these computations. The PROMOD analysis uses a "base case" in which all 17 projects in the MVP portfolio except MVPs 3 and 4 are assumed to be in service, and computes LMP differences between that base case and two "study cases". In the first study case, all 17 MVPs are assumed to be in service. The difference between the load-weighted average electric energy prices without MVPs 3 and 4 in service (Base Case) and the load-weighted average electric energy prices with MVPs 3 and 4 in service (Study Case 1) then represents the wholesale energy price effect from implementing both MVPs 3 and 4. If this difference is negative, as turns out generally to be the case, then this is an indication that MVPs 3 and 4 will lower average wholesale electric energy prices in Minnesota. The annual change in total wholesale market energy payments for Minnesota load is calculated by multiplying these differences by total Minnesota load.

A second study case (Study Case 2) is also examined, in which MVP 3 is assumed to be placed in service, but MVP 4 is not. In this case, the difference between the load-weighted average electric energy prices without MVPs 3 and 4 (Base Case) and the load-weighted average electric energy prices with MVP 3, but not MVP 4 (Study Case 2) then represents the wholesale energy price effect from implementing MVP 3 alone, as compared to the Base Case without both MVPs 3 and 4. These LMP changes provide one measure of the incremental impact of MVP 3.[9]

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[7] In MISO, electricity prices are developed for individual "nodes" on the system. These location-specific "nodal" prices commonly are referred to as locational marginal prices or LMPs. Differences in LMPs from location to location occur because of differences in marginal losses as well as the presence of congestion. When congestion is present, it is not possible fully to exploit differences in marginal generating costs at different locations and LMPs in transmission-constrained areas will rise above LMPs outside those transmission-constrained areas.

[8] These eight Minnesota LSEs are Alliant West—Interstate Power & Light, Dairyland Power Cooperative, Great River Energy, Minnesota Power and Light Company, Minnkota Power Cooperative, Northern States Power Company, Otter Tail Power Company and Southern Minnesota Municipal Power Agency. All but three of these entities also have retail load in states other than Minnesota, requiring the development of a means to unbundle the Minnesota portion of the LMP effects.

[9] An alternative approach to measure the incremental impact of just MVP 3 would be to compare a case with all 17 MVPs except MVP 3 to a case in which all 17 MVPs are developed. Such an analysis implicitly assumes that, in the absence of MVP 3, MVP 4 still would be constructed. However, we understand that MVP 4 would not be developed without MVP 3. Thus, we have not analyzed PROMOD scenarios that assume the construction of MVP 4 but not MVP 3.

The PROMOD analysis quantifies the lower wholesale electric *energy* prices that will result from MVPs 3 and 4, but it does not quantify other potential wholesale electricity price benefits such as lower operating reserve costs and lower capacity requirements and prices. Focusing just on wholesale electric energy price comparison results of the PROMOD analysis therefore will understate the full range of price benefits that can be expected from the MVPs 3 and 4.

As indicated, in addition to the LMP comparisons, the PROMOD analysis that we have conducted also estimates the (adjusted) production costs of meeting MISO load, and develops similar comparisons between cases as those described above for LMPs. Estimated production costs reflect the fuel, variable operations and maintenance, emissions and start-up costs associated with supplying MISO load, adjusted for net imports or exports of power with pools outside MISO.

The PROMOD analyses were run for two future study years, 2021 and 2026, using two different scenarios for each year. These scenarios, which are described further below and which were also used in the MISO MVP Report, contain different assumptions about load growth. The geographic region covered by the PROMOD analysis includes a large portion of the Eastern Interconnection,[10] including all of MISO and the footprint of the adjacent PJM Interconnection and other directly and indirectly interconnected systems.

The following two scenarios were included:

(i) Business as Usual: Low Demand—assumes the continuation of current energy policies and continuing "recession-level" demand and energy growth; and

(ii) Business as Usual: High Demand—assumes the continuation of current energy policies and a return to pre-recession demand and energy growth levels.

These two scenarios are described more completely in Appendix A, attached.

The PROMOD analysis relies largely on the same data used by MISO in its economic analysis of the MVP portfolio. Both the Business as Usual: Low Demand and Business as Usual: High Demand scenarios were also analyzed by MISO in the MISO MVP Report. The assumptions regarding customer demand and energy growth, transmission infrastructure, forecasted fuel prices, and existing and new generation resources are the same as employed by MISO. New renewable resources are added so that each state in the MISO region can comply with its state Renewable Portfolio Standards. Aside from MVPs 3 and 4, the only difference between the study cases and the base case is the quantity of wind power assumed. As discussed more fully in Appendix A, the quantity of wind power resources is reduced from the base case based on ITC's determination that fewer wind resources can be reliably supported without the construction of MVPs 3 and 4.

This Supplemental Report differs from our Initial Report in the following ways: (i) the Supplemental Report develops LMP impacts for MVPs 3 and 4 combined, and MVP 3 without MVP 4, whereas the Initial Report developed LMP impacts for only MVPs 3 and 4 combined; (ii) while the same

[10] The Eastern Interconnection includes roughly the eastern two-thirds of the "lower 48" (with the exception of portions of Texas) plus Canadian provinces to the east of Alberta.

method was employed in each instance, the wind generation curtailment data used for this Supplemental Report was developed by ITC Midwest to allow analysis of MVPs 3 and 4 combined and MVP 3 alone, whereas the wind curtailment data used for the Initial Report was developed by MISO only for MVPs 3 and 4 combined; and (iii) this Supplemental Report includes estimates of annual production cost impacts within MISO associated with MVPs 3 and 4, whereas the Initial Report did not.

3. RESULTS

A. LOCATIONAL MARGINAL PRICE

The estimated price impacts arising from MVPs 3 and 4 are reported in Tables 1 to 3. Table 1 shows the price impacts in each of the study years for Minnesota taken as a whole, for each of the two scenarios evaluated. Tables 2 (Business as Usual: Low Demand) and 3 (Business as Usual: High Demand) then provide the results for the individual Minnesota LSEs.[11] As indicated, Table 1 shows the weighted average prices for Minnesota for each of the scenarios evaluated. The weighted average prices shown reflect each of the eight Minnesota LSEs represented in PROMOD, with weightings in turn reflecting the portion of each company's load that is in Minnesota. In the Business as Usual: Low Demand case for 2021, the Minnesota weighted average LMP is $27.96 with both MVPs 3 and 4 in service and $28.44 without MVPs 3 and 4 in service. The results indicate a weighted average LMP reduction of $0.48 per MWh from the implementation of both MVPs 3 and 4, or 1.7%. In the Business as Usual: High Demand case, the weighted average LMP in 2021 is reduced by $0.52 per MWh from the implementation of both MVPs 3 and 4, or 1.5%. When these weighted average LMP reductions are multiplied by Minnesota load levels, the resulting decreases in annual wholesale energy payments for those Minnesota loads range from $36.1 million for the 2021 Business As Usual: Low Demand Case to $52.5 million for the 2026 Business As Usual: Low Demand Case.

Development of MVP 3 alone (without MVP 4) results in smaller LMP effects. In the Business as Usual: Low Demand case for 2021, the Minnesota weighted average LMP is $28.38 per MWh with MVP 3 (but not MVP 4) as compared to $28.44 per MWh without both MVPs 3 and 4. Thus, the weighted average LMP falls by $0.06 per MWh (0.2%) with the introduction of MVP 3 alone. The LMP reduction from development of MVP 3 under 2021 Business as Usual: High Demand market conditions is $0.05 (0.2%). The resulting decrease in annual wholesale energy payments for 2021 is $4.6 million under Low Demand market conditions and $4.3 million under High Demand market conditions.

Table 2 reports, for the Business As Usual: Low Demand Case, the load weighted LMPs for each Minnesota LSE with and without MVPs 3 and 4. Table 3 reports similar figures for the Business as Usual: High Demand Case. The price effects vary across companies and generally show significant price decreases for all LSEs across study years and growth scenarios after the inclusion of both MVPs 3 and 4.

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[11] The LSEs for which weighted average LMPs are estimated include some that serve only Minnesota customers and others that serve customers in Minnesota and other states. Tables 2 and 3 provide an estimate of the share of each LSE's total load that is accounted for by Minnesota customers developed using data from the Energy Information Administration.

The principal exception, Dairyland Power Cooperative, which has only about 12 percent of its load in Minnesota, experiences a price increase in both scenarios in the 2026 analysis (but not the 2021 analysis). The largest (beneficial) price impacts are for the Southern Minnesota Municipal Power Agency (SMMPA). For example, as shown in Table 2, for SMMPA in 2021 the average LMP is $26.54 with MVPs 3 and 4 in service, and $27.53 without MVPs 3 and 4 in service. Thus, the effect of MVPs 3 and 4 is to lower average LMPs for SMMPA by $0.99, or 3.6%, in 2021. (The effects are similar for the Business as Usual: High Demand Case shown in Table 3.) The smallest price impacts are for Dairyland Power Cooperative. For Dairyland, in 2021, for the Business as Usual: Low Demand Case, the average LMP is $30.97 with MVPs 3 and 4 in service, and $31.15 without MVPs 3 and 4 in service. Thus, the effect of implementing MVPs 3 and 4 is to lower LMPs by $0.19, or 0.6%.

The price effects of developing only MVP 3, compared to a case in which neither MVP 3 nor 4 are developed, vary widely across Minnesota LSEs, with LMPs falling in some LSEs and rising in others.

B. PRODUCTION COSTS

The estimated changes in (adjusted) production costs resulting from MVPs 3 and 4 are provided in Table 4 and 5. Table 4 reports the change in total annual production costs, while Table 5 reports the average change in production costs per MWh load. Production cost impacts reflect the change in annual production costs across all of MISO. Under Business As Usual: Low Demand market conditions in 2021, total annual production costs are $13,217 million with both MVPs 3 and 4 and $13,332 without MVPs 3 and 4. Thus, the development of MVPs 3 and 4 reduces total annual production costs by $114.9 million, or 0.9%. In 2026, under Business As Usual: Low Demand conditions, production costs fall by $136.9 million (0.9%). Decreases in production costs arising from development of both MVPs 3 and 4 under Business As Usual: High Demand market conditions are somewhat higher: $132.2 million (0.8%) in 2021 and $185.6 million (0.9%) in 2026.

The reductions in production costs from developing MVP 3, but not MVP 4, are also reported in Tables 4 and 5 (columns [F] and [G]). Under Business As Usual: Low Demand market conditions in 2021, the development of MVP 3 alone reduces total annual production costs by $42.9 million in 2021 (0.3% of total production costs), and $35.2 million in 2026 (0.2%).

Table 1
LMP Changes from MVPs 3 and 4
Minnesota

	Year	Load Weighted LMP ($ per MWh) With MVPs 3 and 4	Without MVPs 3 and 4	With MVP 3 Only	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [B]	[E] = [D]/[B]	[F] = [C] - [B]	[G] = [F]/[B]
Business as Usual: Low Demand	2021	$27.96	$28.44	$28.38	-$0.48	-1.7%	-$0.06	-0.2%
	2026	$31.16	$31.84	$31.83	-$0.68	-2.1%	-$0.01	0.0%
Business as Usual: High Demand	2021	$34.49	$35.01	$34.96	-$0.52	-1.5%	-$0.05	-0.2%
	2026	$45.20	$45.76	$45.76	-$0.56	-1.2%	$0.00	0.0%

Notes:
[1] All scenarios include all other projects in the MVP portfolio.

Table 2
LMP Changes From MVPs 3 and 4
Business as Usual: Low Demand

Area	Percent Utility Sales in Minnesota	Year	Load Weighted LMP ($ per MWh): With MVPs 3 and 4	Load Weighted LMP ($ per MWh): Without MVPs 3 and 4	Load Weighted LMP ($ per MWh): With MVP 3 Only	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [B]	[E] = [D]/[B]	[F] = [C] - [B]	[G] = [F]/[B]
Alliant West - Interstate Power & Light	5.5%	2021	$29.08	$29.42	$29.65	-$0.34	-1.2%	$0.22	0.8%
		2026	$33.08	$33.28	$33.50	-$0.20	-0.6%	$0.22	0.7%
Dairyland Power Cooperative	11.5%	2021	$30.97	$31.15	$32.72	-$0.19	-0.6%	$1.56	5.0%
		2026	$35.52	$35.30	$37.55	$0.22	0.6%	$2.25	6.4%
Great River Energy	99.6%	2021	$27.47	$28.00	$27.71	-$0.53	-1.9%	-$0.29	-1.0%
		2026	$29.84	$30.58	$30.28	-$0.74	-2.4%	-$0.29	-1.0%
Minnesota Power and Light Company	100.0%	2021	$28.22	$28.63	$28.50	-$0.41	-1.4%	-$0.13	-0.4%
		2026	$31.42	$32.01	$31.87	-$0.58	-1.8%	-$0.14	-0.4%
Minnkota Power Coop	45.1%	2021	$30.22	$30.65	$30.41	-$0.43	-1.4%	-$0.24	-0.8%
		2026	$34.46	$35.17	$34.74	-$0.71	-2.0%	-$0.43	-1.2%
Northern States Power Company	74.8%	2021	$27.91	$28.38	$28.32	-$0.47	-1.7%	-$0.06	-0.2%
		2026	$31.46	$32.16	$32.13	-$0.70	-2.2%	-$0.03	-0.1%
Otter Tail Power Company	48.4%	2021	$28.53	$28.95	$28.62	-$0.41	-1.4%	-$0.33	-1.1%
		2026	$31.03	$31.64	$31.19	-$0.61	-1.9%	-$0.45	-1.4%
Southern Minnesota Municipal Power Agency	100.0%	2021	$26.54	$27.53	$28.66	-$0.99	-3.6%	$1.13	4.1%
		2026	$28.62	$29.54	$31.54	-$0.92	-3.1%	$2.00	6.8%

Notes:
[1] Percent of Utility sales in MN is calculated using EIA data.
[2] All scenarios include all other projects in the MVP portfolio.

Table 3
LMP Changes From MVPs 3 and 4
Business as Usual: High Demand

Area	Percent Utility Sales in Minnesota	Year	Load Weighted LMP ($ per MWh) With MVPs 3 and 4	Without MVPs 3 and 4	With MVP 3 Only	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [B]	[E] = [D]/[B]	[F] = [C] - [B]	[G] = [F]/[B]
Alliant West - Interstate Power & Light	5.5%	2021	$32.42	$33.26	$33.41	-$0.84	-2.5%	$0.15	0.5%
		2026	$39.61	$40.67	$41.01	-$1.06	-2.6%	$0.34	0.8%
Dairyland Power Cooperative	11.5%	2021	$36.05	$36.39	$38.17	-$0.34	-0.9%	$1.78	4.9%
		2026	$44.86	$44.30	$47.29	$0.56	1.3%	$2.99	6.8%
Great River Energy	99.6%	2021	$33.60	$34.20	$33.84	-$0.61	-1.8%	-$0.37	-1.1%
		2026	$42.38	$43.02	$42.75	-$0.64	-1.5%	-$0.27	-0.6%
Minnesota Power and Light Company	100.0%	2021	$33.76	$34.28	$34.12	-$0.51	-1.5%	-$0.16	-0.5%
		2026	$42.00	$42.48	$42.52	-$0.47	-1.1%	$0.04	0.1%
Minnkota Power Coop	45.1%	2021	$36.01	$36.56	$36.15	-$0.56	-1.5%	-$0.41	-1.1%
		2026	$44.83	$45.53	$45.08	-$0.70	-1.5%	-$0.45	-1.0%
Northern States Power Company	74.8%	2021	$35.23	$35.65	$35.64	-$0.42	-1.2%	$0.00	0.0%
		2026	$48.09	$48.62	$48.51	-$0.53	-1.1%	-$0.11	-0.2%
Otter Tail Power Company	48.4%	2021	$33.97	$34.53	$34.04	-$0.56	-1.6%	-$0.48	-1.4%
		2026	$40.98	$41.56	$41.15	-$0.58	-1.4%	-$0.42	-1.0%
Southern Minnesota Municipal Power Agency	100.0%	2021	$31.57	$32.84	$34.09	-$1.27	-3.9%	$1.24	3.8%
		2026	$38.63	$39.48	$41.86	-$0.84	-2.1%	$2.38	6.0%

Notes:
[1] Percent of Utility sales in MN is calculated using EIA data.
[2] All scenarios include all other projects in the MVP portfolio.

Table 4
Adjusted Production Cost Changes From MVPs 3 and 4
All of MISO

	Year	Adjusted Production Cost ($ Millions): With MVPs 3 and 4	Adjusted Production Cost ($ Millions): Without MVPs 3 and 4	Adjusted Production Cost ($ Millions): With MVP 3 Only	Change in Production Cost Due to MVPs 3 and 4 ($ Millions)	Percent Difference	Change in Production Cost Due to MVP 3 ($ Millions)	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [B]	[E] = [D]/[B]	[F] = [C] - [B]	[G] = [F]/[B]
Business as Usual: Low Demand	2021	$13,217	$13,332	$13,289	-$114.9	-0.9%	-$42.9	-0.3%
	2026	$15,474	$15,611	$15,576	-$136.9	-0.9%	-$35.2	-0.2%
Business as Usual: High Demand	2021	$15,821	$15,953	$15,903	-$132.2	-0.8%	-$49.5	-0.3%
	2026	$20,308	$20,494	$20,451	-$185.6	-0.9%	-$43.5	-0.2%

Notes:
[1] All scenarios include all other projects in the MVP portfolio.

Table 5
Adjusted Production Cost per MWh Load Changes From MVPs 3 and 4
All of MISO

	Year	Adjusted Production Cost per MWh Load ($/MWh) With MVPs 3 and 4	Without MVPs 3 and 4	With MVP 3 Only	Change in Production Cost Due to MVPs 3 and 4 ($/MWh)	Percent Difference	Change in Production Cost Due to MVP 3 ($/MWh)	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [B]	[E] = [D]/[B]	[F] = [C] - [B]	[G] = [F]/[B]
Business as Usual: Low Demand	2021	$22.82	$23.02	$22.95	-$0.20	-0.9%	-$0.07	-0.3%
	2026	$25.65	$25.88	$25.82	-$0.23	-0.9%	-$0.06	-0.2%
Business as Usual: High Demand	2021	$25.67	$25.88	$25.80	-$0.21	-0.8%	-$0.08	-0.3%
	2026	$30.66	$30.94	$30.87	-$0.28	-0.9%	-$0.07	-0.2%

Notes:
[1] All scenarios include all other projects in the MVP portfolio.

Appendix A

PROMOD Modeling and Data

This appendix provides a summary of the PROMOD IV (PROMOD) model, data and assumptions used in analyzing the MVPs 3 and 4, and the methodology for estimating the effect of MVPs 3 and 4 on wholesale electric energy prices in Minnesota and annual production costs within the footprint of the Midwest Independent Transmission System Operator, Inc. (MISO).

1. THE PROMOD MODEL

PROMOD is an electric market simulation model marketed by Ventyx. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices (LMPs) at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generator output. It can also perform and support various reliability analyses, including calculation of loss-of-load probability, expected unserved energy, and effective capacity support.

2. DATA AND ASSUMPTIONS

The analysis relies largely on data developed by MISO in its Multi Value Project (MVP) process. A detailed description of MISO's MVP process and data analysis is provided in the MVP Report.[12] As described by MISO, the principal purposes of the MVPs are "to meet one or more of three goals: reliably and economically enable regional public policy needs; provide multiple types of economic value; and provide a combination of regional reliability and economic value."[13] To identify these transmission projects, MISO has performed detailed economic and engineering analyses of many alternative transmission projects and portfolios using PROMOD.

The data and assumptions used by MISO in its MVP analysis are based on Ventyx-provided data, and have been modified as needed by MISO. These data include:

1. load forecasts provided by individual utilities within MISO,[14]

[12] MISO, Multi Value Project Portfolio: Results and Analyses, January 10, 2012 (hereafter "MVP Report").

[13] MISO website, available at https://www.midwestiso.org/Planning/Pages/MVPAnalysis.aspx, accessed November 6, 2012.

[14] Demand and energy growth rates for each region are provided in: MISO, *MISO Transmission Expansion Plan 2011: PROMOD Case Assumptions Document*, p 23 ("MTEP PROMOD Assumptions" hereafter).

2. transmission line data from transmission operators,[15]
3. unit specifications for existing generation resources,[16]
4. new generation resources based on units planned and under construction,[17]
5. future generation resource additions developed by a capacity expansion model,[18]
6. retirement of generation facilities based on currently announced retirements, but not in response to economic or regulatory factors, including EPA regulation,[19]
7. "hurdle rates" for transactions between NERC regions,[20] and
8. fuel and emission price forecasts.

The system modeled includes individual generator data and complete transmission information for the Eastern Interconnection,[21] at the bus[22] level.

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[15] Transmission constraints are based on the most recent Book of Flowgates from MISO and North American Electric Reliability Corporation (NERC), updated to include rating and configuration changes from studies performed during the MTEP 11 process. Transmission line data includes items such as the voltage rating of the line and the buses that each line runs between.

[16] Individual unit specifications include maximum operating capacity; fuel type; variable costs; no-load and startup costs; minimum run times; emission rates; and heat rate curves.

[17] Detailed information on the existing, under construction and planned units in each region is provided in MTEP PROMOD Assumptions, p 17.

[18] MISO relies upon the Electric Generation Expansion Analysis System (EGEAS) model developed by the Electric Power Research Institute. EGEAS is designed to find the optimized capacity expansion plan to meet forecast demand (load plus planning reserve margin target minus losses) through a least cost-mix of supply-side and demand-side resources. Planning reserve margins are identified in MTEP PROMOD Assumptions, pp 23-24.

[19] As part of MTEP 2011, MISO performed an EPA Regulation Impact Analysis that identifies planning needs arising from the retirement of coal-fired generation facilities due to EPA regulations and other market factors (*e.g.*, competition from natural gas-fired generation). Aside from those already announced, MISO's MVP analysis does not incorporate any retirements of coal-fired generation.

[20] PROMOD allows power to flow between regions based on economic transactions (subject to security constraints and congestion) such that prices must exceed generator costs in a neighboring region by a dollar per MWh "hurdle rate" in order for power to flow across regions.

[21] The Eastern Interconnection comprises roughly the eastern two-thirds of the "lower 48" (excluding portions of Texas), including the Canadian provinces east of Alberta and the following NERC regions: Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), SERC Reliability Corporation (SERC), Florida Reliability Coordinating Council (FRCC), Reliability*First* Corporation (RFC), and Northeast Power Coordinating Council (NPCC). MISO's PROMOD modeling excludes Peninsular Florida, New England, and Eastern Canada, but accounts for aggregate regional flows to and from these areas through the use of fixed transactions. For more detail, see MTEP PROMOD Assumptions, p 24.

[22] A bus is the specific geographical point that a generator is located at or that a transmission line connects to.

The quantity and location of future renewable resources, including wind and solar, are determined by MISO both to meet state RPS requirements and reduce the combined cost of renewable and transmission resources.[23] Based on these requirements, MISO's analysis assumes that, with its full 17 MVP project portfolio[24] in service, 8,765 MW of new wind resources are added in 2021, and an additional 2,272 MW of new wind resources are added by 2026.[25]

MVPs 3 and 4 represent two projects within the MVP portfolio.[26] These two projects are listed in Table A1, and are shown geographically in Figure A1. The analyses herein make two comparisons. The first comparison is between a study case that includes all 17 MVP projects in MISO's portfolio and a study case that includes all 17 of these MVP projects except MVPs 3 and 4. We refer to the first of these cases as the 17 MVP study case and to the second as the 15 MVP study case. This comparison provides an indication of the impacts of developing both MVPs 3 and 4. The second comparison is between a case that includes all 17 MVP projects in MISO's portfolio except MVP 4 — which we refer to as the 16 MVP study case — and the 15 MVP study case. This comparison provides an indication of the impacts of developing MVP 3 in the absence of MVP 4.

All three study cases include each of the 15 MVPs other than MVPs 3 and 4. Apart from differences in which MVPs are included in each case, the only other differences among the cases relates to the quantity of new wind generation resources assumed to be in service. In the 15 and 16 MVP study cases, the quantity of new wind resources has been reduced from the level in the case with all 17 MVPs because of the diminished ability of the transmission system to support that wind capacity without the additional MVPs. Unless new wind additions are reduced in this fashion, power flows may exceed line capacities under certain contingencies. To determine the quantity of wind capacity that can be supported in the 15 and 16 MVP study cases, ITC performed an analysis to identify the minimum quantity of wind capacity curtailments that would still allow line loadings to be kept within limits. In performing this analysis, ITC utilized the same general methodology as MISO when it developed the wind curtailments values for its MVP Report and for our Initial Report. Based on ITC's analysis, the 15 MVP and 16 MVP study cases have, respectively, 1,130 MW and 689 MW less wind capacity than the 17 MVP study case.

[23] MISO determined the amount of wind enabled by the MVP portfolio by first determining the amount of wind needed to meet RPS targets, and then determining what amount of wind would not be supported but for the MVP portfolio. This process is detailed by MISO in the MVP Report, pp 17-20 and 48-49.

[24] The full 17 MVP portfolio is identified in Table 1.1 of the MVP Report.

[25] Table 4.2, MVP Report. MISO also finds that the MVP portfolio can support an additional 2,230 MW of additional wind power from the wind zones without incurring additional reliability constraints. MVP Report, pp 48-49.

[26] These two are: (1) Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster and (2) Winco–Lime Creek–Emery–Black Hawk–Hazleton.

Table A1

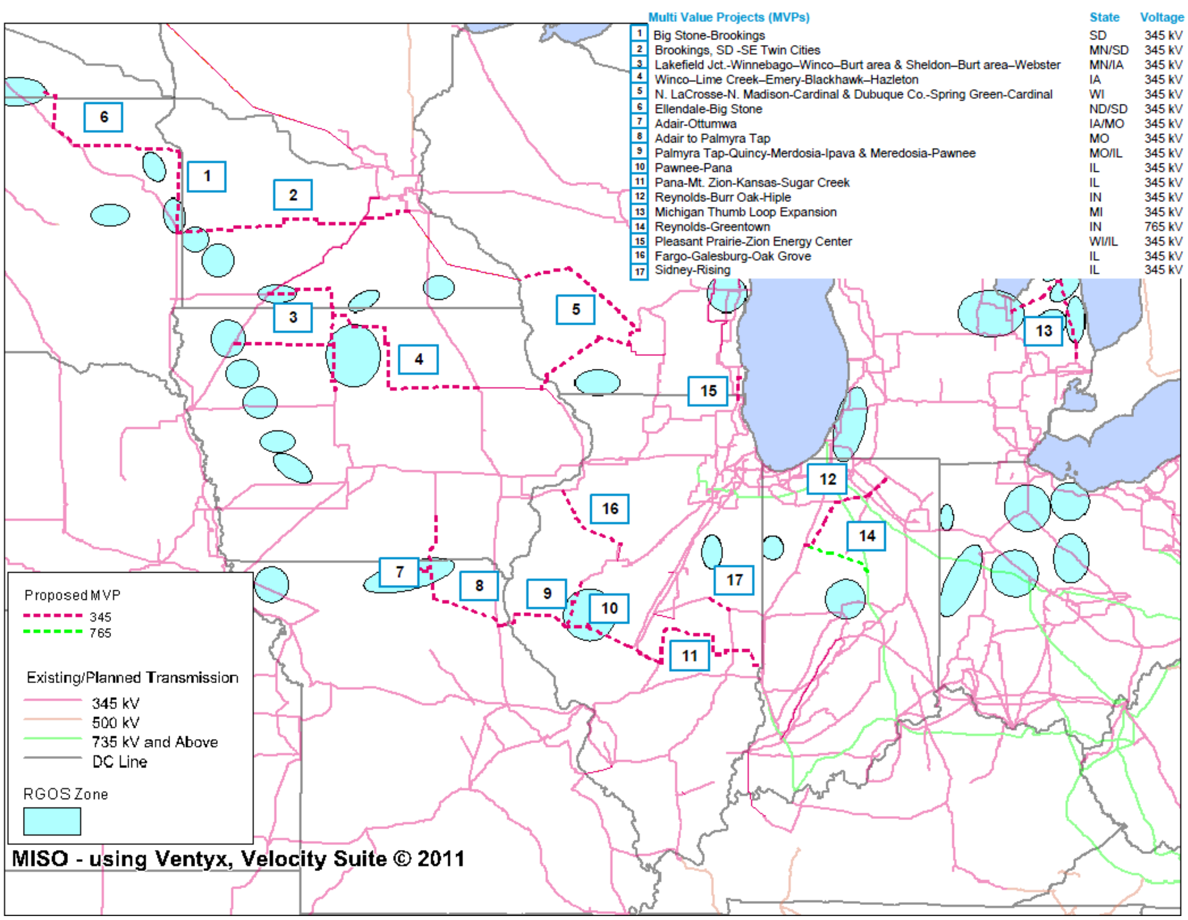
Project Elements

MVP Element	Project	Voltage	In-Service Year
3	Lakefield Jct.–Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	345	2016
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	345	2015

Source: MISO MVP Report.

Figure A1

Map of MVP Portfolio



Source: MISO MVP Report.

3. ANALYTICAL METHOD

The analysis herein provides estimates of changes in wholesale electric energy prices, measured through LMPs, and annual production costs, as a result of implementing MVP 3 (with and without also implementing MVP 4). We also provide estimates of changes in annual wholesale energy payments for Minnesota resulting from the LMP changes.

The computation of wholesale electric energy prices and annual payments is based on two outputs from the PROMOD model: area LMPs and area loads. Within PROMOD, areas generally correspond to the service territories of load-serving entities. A "Minnesota area" as used below refers to a PROMOD area that includes some portion of Minnesota. The process used to develop changes in wholesale energy prices is as follows:

1. Hourly area LMPs are calculated by PROMOD and reflect the load-weighted LMP of all nodes within the area.
2. Minnesota Area LMPs are calculated, which reflects the annual average of the hourly area LMP, weighted by the hourly area load.[27] Area load is based on the PROMOD inputs developed by MISO, and reflects hour-by-hour load forecasts for individual areas within MISO.[28] For areas that include portions of both Minnesota and one or more neighboring states, the Minnesota area LMPs are assumed to equal the prices across the entire area.
3. A Minnesota load-weighted LMP is calculated, which reflects each Minnesota area's weighted average LMP and each Minnesota area's load. Because some Minnesota areas include portions of both Minnesota and one or more neighboring states, an adjustment must be made to the MISO area loads to estimate the quantity of load only inside Minnesota. To make this adjustment, the percent of each area's load that is in Minnesota is calculated. These percentages, which are reported in Tables 2 and 3, are developed using data from the Energy Information Administration.[29] To calculate the Minnesota area load, each area's total load is multiplied by the percent of that area's load that is in Minnesota. To calculate the load-weighted LMP for Minnesota, each Minnesota area's LMP, calculated as described above in #2, is weighted by the estimated load for each Minnesota area, as described above.
4. The change in annual wholesale energy payments for Minnesota is calculated by multiplying the total Minnesota load, based on the calculations noted in #3 above, and the change in LMP between (i) the 17 MVP study case and the 15 MVP study case; and (ii) the 16 MVP study case and the 15 MVP study case.

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[27] Hours in which the LMP for a Minnesota area is less than -$10/MWh are dropped for the purposes of calculating an annual load-weighted average LMP. Hours in which the LMP for a Minnesota area is greater than $1,000/MWh are capped at $1,000/MWh.

[28] These loads reflect forecasts for annual peak load and annual energy shaped over 8,760 hours.

[29] See Form EIA-861 data files, available at http://www.eia.gov/electricity/data/eia861/index.html, accessed September 20, 2012.

The analysis also estimates changes in (adjusted) production costs across the entire MISO region. Production costs include fuel, variable operations and maintenance, emissions and start-up costs for all units operating in the MISO market. These production costs are then adjusted to account for net imports or exports of power between MISO and other regions operating in the Eastern Interconnection. Net transfers between pools are priced at the hourly weighted average LMP for MISO, consistent with the methodology used by MISO when it estimates adjusted production costs. Average LMPs are weighted by generation output when net flows with other regions are positive, and are weighted by load when net flows with other regions are negative. Changes in annual production costs between scenarios are calculated in the manner described in item #4, above.

4. SCENARIOS

The results presented in the body of this report reflect two scenarios, which are detailed below and in Table A2. Each scenario was designed by MISO in its MVP portfolio analysis, and no additional changes have been made. The definitions are provided by MISO in its MVP portfolio analysis report.[30]

- **Business As Usual: Low Demand** – assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.[31]
- **Business As Usual: High Demand** – assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.[32]

[30] MVP Report, p 52.

[31] Note that the MVP Report titles this case "Business As Usual with Continued Low Demand and Energy Growth (BAULDE)."

[32] Note that the MVP Report titles this case "Business As Usual with Historic Demand and Energy Growth (BAUHDE)."

Table A2

Scenario Assumptions[33]

Future Scenarios	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
Business As Usual: Low Demand	State RPS	0.78 percent	0.79 percent	BAU	None
Business As Usual: High Demand	State RPS	1.28 percent	1.42 percent	BAU	None

[33] Table A2 is based on Table 8.1 from the MVP Report.

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G	Upper Midwest Transmission Development Initiative, Executive Committee Final Report (Sept. 29, 2010)
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I	MISO Transmission Expansion Plan 2011 (Report Only. Appendices available at https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/MTEP11.aspx)
J	ITC Midwest LLC MVP Project #3 Planning Study
K	Proposed MVP Reliability Analysis of Alternative Discussion (MISO Presentation, Sept. 16, 2011) (Excerpt)
L	Candidate MVP Reliability Analysis Wind Curtailment (MISO Presentation, July 13, 2011)
M	LMP Impacts of Proposed Minnesota – Iowa 345 kV Transmission Project
N	LMP Impacts of Proposed Minnesota – Iowa 345 kV Transmission Project- Supplemental Analysis

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(Revised April 9, 2013)