STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota-Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties	PUC Docket No. ET6675/CN-12-1053 OAH Docket No. 60-2500-30782
In the Matter of the Application of ITC Midwest LLC for a Route Permit for the Minnesota-Iowa 345 kV Transmission Project and Associated Facilities in Jackson, Martin, and Faribault Counties	PUC Docket No. ET6675/TL-12-1337 OAH Docket No. 60-2500-30782

REBUTTAL TESTIMONY OF

TODD SCHATZKI

On Behalf of

ITC MIDWEST LLC

April 25, 2014

Exhibit _____

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I. INTRODUCTION AND QUALIFICATIONS

Q. **PLEASE STATE YOUR NAME.**

A. My name is Todd Schatzki.

Q. **HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?**

A. Yes. I submitted direct testimony in which I provided estimates of the changes in locational marginal prices ("LMPs"), production costs, and emission costs associated with implementation of the Minnesota – Iowa 345 kV Transmission Project ("Project"). 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. The Project, together with other facilities being proposed by MidAmerican Energy Company ("MidAmerican") to be constructed in Iowa, comprises what is referred to as MVP Project 3 in MISO's MVP Portfolio.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony assesses certain elements of the direct testimony of Dr. Steve Rakow on behalf of the Minnesota Department of Commerce, Division of Energy Resources ("DOC-DER"). In his testimony, Dr. Rakow provides an analysis of the "costs and benefits" of the proposed MVP Project 3 (with and without MVP Project 4) and 161 kV Rebuild Alternative. In my rebuttal testimony, I address several aspects of his assessment. First, I provide alternative estimates of the differences in the "costs and benefits" between transmission alternatives based on more appropriate measures of the factors Dr. Rakow seeks to account for. Second, I discuss Dr. Rakow's assessment of "other factors" not addressed in his analysis of costs and benefits. I show how the approach he uses to assessing other factors can lead to inaccurate conclusions, provide an alternative metric for the only additional factor he explicitly evaluates (transfer capability), and identify other factors he does not consider.

Q. **SUMMARIZE YOUR CONCLUSIONS.**

A. Based on my analysis of the factors considered by Dr. Rakow in his comparison of transmission alternatives, I find that MVP Project 3 (with or without MVP Project 4) is expected to provide greater net benefits than the 161 kV Rebuild Alternative. My analysis is based on more reliable and comprehensive estimates of project impacts to Minnesota customers, including the use of production cost, rather than LMP impacts, and the use of emission costs based on all changes in emissions, rather than only those arising from reductions in transmission line losses.

I also find that Dr. Rakow's assessment of transfer capability leads to misleading conclusions about the relative merits of transmission alternatives, and that the greater transfer capability provided by MVP Project 3 (with or without MVP Project 4) should have led Dr. Rakow to conclude that, all else equal, MVP Project 3 is preferred to the 161 kV Rebuild Alternative. In addition, I show that a different metric of transmission benefits suggests that the benefits provided by MVP Project 3 relative to the 161 kV Rebuild Alternative are much greater than the transfer capability metric used by Dr. Rakow. I also note that Dr. Rakow's analysis does not consider many other factors that would affect the net benefits provided by transmission alternatives.

Q. DO YOU HAVE ANY CORRECTIONS TO YOUR DIRECT TESTIMONY?

A. Yes. I have two corrections. First, **Schedule 2** of my direct testimony provided a copy of my November 2013 report in which Table A3 was missing. To address this, I have provided a corrected version of **Schedule 2**. Second, in **Schedule 3** of my direct testimony, Tables 3-5 and 3-6 were calculated using a different set of MISO utilities than my production cost estimates. To maintain consistency, I have provided a corrected version of **Schedule 3** with revised versions of Tables 3-5 to 3-6.

Q. WHAT SCHEDULES ARE YOU PROVIDING IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Corrected Schedule 2: Supplemental Response to Department of Commerce, Division of Energy Resources ("DOC-DER") Information Request No. 11 dated November 27, 2013, including Attachment 11-1, LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis, November 2013.

Corrected Schedule 3: Table 3-1 through Table 3-6, LMP, Production Cost and Other Social Cost Changes.

Schedule 4:	Tables 1A through Tables 5C, Differences in Social Costs Between Alternatives, and Production Cost and Other Social Cost Changes

II. DR. RAKOW'S INTERNAL AND SOCIAL COST ANALYSIS

Q. CAN YOU DESCRIBE THE ECONOMIC ANALYSIS OF ALTERNATIVES PROVIDED BY DR. RAKOW?

A. Yes. Dr. Rakow evaluates the "costs and benefits" of the proposed MVP Project 3 (with and without MVP Project 4) and the 161 kV Rebuild Alternative. MVP Project 3 and Project 4 were described in my direct testimony and the direct testimony of Joe Berry. With the 161 kV Rebuild Alternative, the existing transmission line from the Fox Lake-Rutland-Winnebago Junction, which has been a main constraint on the electrical system in the region, would be rebuilt. This rebuild would include new structures and conductors, and would increase the line's rating from 168 MVA to 446 MVA. In Dr. Rakow's analysis, he compares cost and benefits under the assumption that all other elements of the MVP Portfolio are in service (except for certain cases that assume MVP Project 5 is not in service). For example, his assessment of the costs and benefits of MVP Project 3 and Project 4 is based on a comparison a case in which all MVPs except MVP Project 3 and Project 4 are in service against a case in which all MVPs (including MVPs Project 3 and Project 4) are in service.

Q. CAN YOU DESCRIBE THE "COSTS AND BENEFITS" ACCOUNTED FOR BY DR. RAKOW IN HIS ANALYSIS?

A. Yes. Dr. Rakow's analysis of costs and benefits reflects three components: construction costs of new transmission infrastructure, locational marginal price ("LMP") impacts and other social costs, in particular externality costs associated with fossil fuel emissions. He refers to the sum of the first two of these components as "internal costs", and the sum of all three components as "social costs". I will use these terms and will also refer to the net impact of these components as the "net benefit". Dr. Rakow measures these costs for Minnesota loads, but not any broader geographic areas, such as the entire MISO footprint. That is, construction costs reflect Minnesota customer's expected allocation of project costs, LMP impacts reflect anticipated future Minnesota customer loads, and emission impacts are measured with respect to the transmission losses on the systems serving Minnesota customers.

Q. HAVE YOU DEVELOPED ALTERNATIVE ESTIMATES OF THE COSTS AND BENEFITS FROM THE STANDPOINT OF MINNESOTA, SIMILAR TO DR. RAKOW?

A. Yes. Table 1A reports alternative estimates of the difference in the social costs of MVP Project 3 and Project 4 combined and the costs of the 161 kV Rebuild Alternative. A negative number indicates that MVP Project 3 and Project 4 have lower internal costs (greater net benefits) than the 161 kV Rebuild Alternative. The results in the top left corner of Table 1A provide results that reflect what I'll refer to as "reference" assumptions, with two alternative demand levels, for 2021 and 2026. Under "reference" assumptions, all other MVPs (including MVP Project 5) are developed and construction costs equal ITC Midwest's current estimates ("expected cost"). Other results in the table consider sensitivities to the reference assumptions, including sensitivities in which MVP Project 5 is not developed and sensitivities with a 30 percent increase and decrease in construction costs.

The values in Table 1A reflect three elements: transmission construction costs, changes in production costs and changes in the social cost of aggregate emissions. I refer to these as Minnesota Social Costs. There are two primary differences between my estimates of Minnesota Social Costs and the social costs estimated by Dr. Rakow and reported in his Table 5:[1] first, Minnesota Social Costs reflect changes in consumer electricity expenditures based on expected changes in production costs rather than changes in LMPs; second, Minnesota Social Costs reflect social costs based on all expected changes in emissions associated with supplying Minnesota customers with electricity, as calculated in my PROMOD analysis, rather than only expected changes in emissions from transmission line losses, as calculated by Dr. Rakow. Additional details on how these measures are

[1] Throughout my analyses, I adopt the same estimates of transmission costs developed by Dr. Rakow.

calculated and why they are more appropriate measures of social costs than those used by Dr. Rakow are provided later in my testimony.

As shown in Table 1A, under the reference assumptions, MVP Project 3 and 4 combined provides greater expected net benefits than the 161 kV Rebuild Alternative in all years and for both low and high levels of demand. The table also shows that this result holds when construction costs are increased or decreased by 30 percent. Across the cases with MVP Project 5 in service, the annual net benefits of MVP Project 3 and Project 4 (relative to the 161 kV Rebuild Alternative) range from $9.1 million to $30.6 million. When MVP Project 5 is not in service, MVP Project 3 and Project 4 has greater net benefit in the majority of cases, while there are certain cases (five of twelve) when the 161 kV Rebuild Alternative has greater net benefits.

Table 1B considers MVP Project 3 alone (without MVP Project 4) in comparison to the 161 kV Alternative. The table shows that MVP Project 3 alone provides greater net benefits than the 161 kV Rebuild Alternative in 21 of 24 cases. With MVP Project 5 in service, the annual net benefits of MVP Project 3 alone (relative to the 161 kV Rebuild Alternative) range from $8.6 million to $22.7 million. When MVP Project 5 is not in service, the relative net benefits of MVP Project 3 alone range from a decrease of $7.1 million to an increase of $4.6 million.

Q. DOES DR. RAKOW'S ANALYSIS OF COSTS AND BENEFITS ACCOUNT FOR ALL DIFFERENCES BETWEEN TRANSMISSION ALTERNATIVES?

A. No. As noted by Dr. Rakow, his analysis of social costs does not account for all factors relevant to assessing the choice between transmission alternatives. Dr. Rakow considers one factor in particular – transfer capability – and acknowledges that MVP Project 3 (with or without MVP Project 4) provides greater benefits than the 161 kV Rebuild Alternative, although he does not account for this difference in his assessment of costs and benefits. He also does not account for other potential differences between the options, including changes in capacity, reserve and other ancillary service requirements, support for regional reliability and policy objectives, and changes in market competition and market liquidity. Further, he does not account for other reliability and transmission benefits, which are addressed by ITC Midwest witness Joe Berry. Later in my testimony I discuss these additional factors in greater detail.

Q. DID MISO PERFORM AN ASSESSMENT SIMILAR TO THAT PERFORMED BY DR. RAKOW?

A. Yes. In *Multi-Value Project Portfolio, Results and Analyses* ("MVP Report"),[2] MISO provides an assessment of costs and benefits similar in concept to that of Dr. Rakow. However, there are important differences. While Dr. Rakow's analysis assumes that all other MVP elements other than MVP

[2] MISO, "Multi-Value Project Portfolio, Results and Analyses," January 10, 2012.

Project 3 and Project 4 are in service, MISO's evaluation reflects the fact that the MVP Project 3 is but one element in an *integrated portfolio* of projects that is designed to provide net benefits to the MISO region as a whole and to the states within MISO individually. Thus, when assessing this portfolio, MISO compared a case with the full MVP portfolio to a case without the MVP portfolio, and evaluated net benefits to the MISO footprint as whole as well as benefits to each of seven zones within MISO.[3]

Q. WHAT DID MISO CONCLUDE?

A. MISO concluded that the MVP portfolio would "[p]rovide benefits in excess of its costs under all scenarios studied, with its benefit to cost ratio ranging from 1.8 to 3.0."[4] MISO also evaluated the benefits and costs to seven zones within MISO, finding that ratios of benefits to costs ranged from 1.6 to 3.3 across zones.[5]

Q. DID MISO ALSO CONSIDER ALTERNATIVES TO THE MVP PORTFOLIO?

A. MISO did not evaluate alternatives to the MVP portfolio within the MVP Report. However, the MVP Report was preceded by many other analyses

[3] There are many other differences between Dr. Rakow and MISO's analyses. For example, Dr. Rakow considers LMP impacts, while MISO considers changes in production costs, as I do in my analysis. In addition, MISO quantitatively analyzes other types of production cost changes, such as reductions in costs from lower capacity and reserve requirements.

[4] MVP Report, p. 1.

[5] The majority of Minnesota is in Zone 1, which also includes North Dakota, parts of Montana, South Dakota and Wisconsin. A small portion of Southern Minnesota is in Zone 3, which also includes all of Iowa and a very small portion of Illinois. MVP Report, Figure 1.5.

in which MISO, through processes including stakeholder input, evaluated alternatives to the MVP portfolio in terms of various cost, reliability and other policy factors. One such process was the Regional Generation Outlet Study. Regarding this study, the MVP Report notes that: "This study was intended, at a high level, to identify the transmission required to support the renewable mandates and goals of the MISO states, while minimizing the cost of energy delivered to customers."[6]

Q. WHAT ARE THE IMPLICATIONS OF THE DR. RAKOW'S ANALYSIS OF COSTS IN THE CONTEXT OF THE ANALYSIS PREVIOUSLY PERFORMED BY MISO?

A. The MISO test considered a criterion that is necessary to demonstrating the benefits of adopting the MVP portfolio. The test assumes that the decision to develop the MVP portfolio needs to be considered as a whole and asks whether the portfolio provides net benefits to the MISO footprint as a whole and to individual regions within MISO.

By contrast, Dr. Rakow's test considers whether one particular element of the portfolio – MVP Project 3 – provides benefits (to a particular set of consumers) assuming that all other states and market participants take the steps needed to develop all of the other MVP portfolio elements. While this test potentially provides greater assurance that a particular element of the

[6] MISO, MVP Report, p. 16.

MVP portfolio is beneficial to Minnesota customers, it is not necessary to reaching such a conclusion.

Q. HAVE YOU EVALUATED ECONOMIC OUTCOMES FROM THE BROADER SOCIAL PERSPECTIVE TAKEN IN MISO'S ANALYSIS?

A. Yes. Tables 2A and 2B provide a comparison of transmission alternatives in which net benefits, including production costs and emission costs, are estimated for the entire MISO footprint. Table 2A compares MVP Project 3 and Project 4 combined to the 161 kV Rebuild Alternative, while Table 2B compares MVP Project 3 (without MVP Project 4) to the 161 kV Rebuild Alternative. As with Tables 1A and 1B, a negative value indicates that MVP Project 3 and Project 4 combined has greater net benefits than the 161 kV Rebuild Alternative. Evaluated across the MISO footprint, MVP Project 3 (with or without Project 4) provides greater net benefits than the 161 kV Rebuild Alternative under all scenarios evaluated. The difference in net benefits ranges from $132 million to $259 million across cases for MVP Project 3 and Project 4 combined (Table 2A), and from $5 million to $103 million for MVP Project 3 alone (Table 2B).

Q. DOES DR. RAKOW'S FOCUS ON SOCIAL COSTS TO MINNESOTA ACCOUNT FOR ALL FACTORS RELEVANT TO MINNESOTA CUSTOMERS?

A. Potentially not. Dr. Rakow's assessment of impacts to Minnesota does not account for broader impacts of Minnesota's decisions beyond its borders. Even if Minnesota should choose not to account for impacts beyond its borders in its assessment, it is important to recognize the potential for broader regional benefits through cooperation with other states in the region, and how best to achieve such cooperation at present and in the future.

Even if a decision to reject MVPs Project 3 was narrowly in Minnesota's best interests (which as I show above, it is not), this decision could adversely affect the region's ability to derive the full benefits from the MVP portfolio. As shown in Tables 2A and 2B, without MVP Project 3, the MVP portfolio would provide fewer benefits to the MISO region than if the project to be developed. Further, if other states were to reject MVPs requiring state Commission or agency approval, then the aggregate benefits achieved by the MVP portfolio would further diminish. Because the MVP portfolio was designed as an integrated suite of projects, the elimination of individual projects could adversely affect the value provided by others, thus further influencing subsequent decisions regarding the development of individual MVPs.

In this regard, it is worth noting that Minnesota does appear to clearly benefit from the development of other MVPs outside of Minnesota. While I have not systematically evaluated the incremental benefits of individual MVPs to Minnesota, following on an information request from the DOC-DER, I have evaluated cases that can be used to estimate the impacts of MVP Project 5 on outcomes within Minnesota. Tables 3A to 3C provide estimates of Minnesota Production Costs, which I will describe in greater detail later in my testimony. Comparing cases with and without MVP Project 5 provides an estimate of the benefit to Minnesota customers from the development of MVP Project 5. For example, in 2021 with Low Demand, when MVP Project 3 and Project 4 are in service, Minnesota Production Costs are $1,332 million with MVP Project 5 in service and $1,419 million with MVP Project 5 not in service. Thus, in this case, Minnesota Production Costs decline by $87 million with the development of MVP Project 5. Across cases in Tables 3A to 3C, the development of MVP Project 5 reduces Minnesota Production Costs by $70 million to $136 million. Thus, the development of MVP Project 5 would provide Minnesota with substantial benefits.

More generally, Minnesota's actions could affect the willingness of other states to participate in regional solutions to policy problems, including those beyond the MVP process. Like the MVP portfolio, many policy problems can only be resolved optimally through cooperation among otherwise independent entities. Achieving cooperation among independent entities, such as states, to address such problems is often a challenge, particularly if acting "non-cooperatively" appears more beneficial.

Within economics, this cooperation problem can be represented as a *prisoner's dilemma.* The prisoner's dilemma is a well-known problem, in which two prisoners must choose to “cooperate” or “defect” with the each other. They are better off if they both agree to cooperate as compared to the outcome if they both defect. However, when each considers his narrow interests, the payoff is higher from defecting regardless of what the other prisoner does. Consequently, they both defect and are unable to achieve the more preferable cooperative outcome. This model is often used to represent challenges with reaching cooperative outcomes because it captures the temptation that often exists for one entity to defect from a cooperative agreement because of the perceived immediate gains.

III. ALTERNATIVE ESTIMATES OF DR. RAKOW’S INTERNAL AND SOCIAL COSTS

Q. CAN YOU DESCRIBE DR. RAKOW’S ANALYSIS OF LMP IMPACTS?

A. Dr. Rakow calculates LMP impacts based on the change in wholesale prices and the total Minnesota electricity load. The wholesale prices used by Dr. Rakow were provided in my direct testimony (and referred to therein as “Minnesota Avg LMPs”) based on analysis of the MISO wholesale electricity markets developed using the PROMOD market simulation model. These prices reflect the state-wide weighted average Locational Marginal Prices or “LMPs”. Dr. Rakow, it appears, calculates the change in average wholesale energy payments as a means of capturing a portion of "the costs for electric consumers in Minnesota."[7]

Q. DOES DR. RAKOW'S ANALYSIS OF LMP IMPACTS PROVIDE AN ACCURATE ESTIMATE OF THE CHANGES IN CONSUMER EXPENDITURES?

A. No. An estimate of costs based on LMPs does not provide an accurate measure of the expenditures Minnesota customers will make for electricity. As described in my direct testimony, LMPs do not generally provide an accurate measure of customer expenditures when those customers are served by companies with rates that are set based on the cost-of-service. Under these circumstances, the prices charged to customers will generally reflect costs of producing power, rather than wholesale market prices. LMPs potentially affect these costs of service to the extent that a particular company is a net supplier or purchaser of power (beyond their various assets, including contractual obligations for power supply or ownership in facilities), although such effects are typically small in relation to production costs. Because Minnesota customers are served by companies that charge rates that are set based on the cost-of-service, a more accurate measure of costs to Minnesota customers is production costs.

[7] Dr. Rakow may refer to statutes indicating that the Commission must consider "the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives." Rakow direct testimony, pp. 8 and 19.

Q. HAVE YOU DEVELOPED ESTIMATES OF THE PRODUCTION COSTS FOR ELECTRICITY DELIVERED TO MINNESOTA CUSTOMERS?

A. Yes. My direct testimony provided estimates of the changes in MISO Production Costs when MVP Project 3 is developed with and without MVP Project 4. These 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.

In this testimony, I provide estimates of the change in production costs to supply Minnesota load associated with MVP Project 3 (with and without MVP Project 4) and the 161 kV Rebuild Alternative. I refer to these as Minnesota Production Costs. These costs reflect the fuel, variable operations and maintenance, emissions and start-up costs associated with supplying *Minnesota* load, adjusted for net imports or exports of power with areas outside of Minnesota, including areas within and outside of MISO.

Q. DESCRIBE THE RESULTS OF YOUR ANALYSIS OF MINNESOTA PRODUCTION COSTS, REPORTED IN TABLE 3.

A. Tables 3A, 3B and 3C provide estimates of the annual change in Minnesota Production Costs as a consequence of placing new transmission infrastructure into service. Table 3A considers MVP Project 3 and Project 4 combined, Table 3B considers MVP Project 3 alone (without MVP Project

4) and Table 3C considers the 161 kV Rebuild Alternative.[8] As shown in Table 3A, Minnesota Production Costs decline by $19.3 million to $27.5 million annually with the addition of MVP Project 3 and Project 4 when MVP Project 5 is in service. When MVP Project 5 is not in service, Minnesota Production Costs decrease by $6.6 million to $8.5 million annually across three cases, and increase by $8.4 million in one case. When only MVP Project 3 is in service (without MVP Project 4) and MVP Project 5 is in service, Minnesota Production Costs decline by $14.1 million to $20.4 million annually. When MVP Project 5 is not in service, these costs range from a decrease of $4.4 million to an increase of $1.6 million across cases. With the 161 kV Rebuild Alternative in service, Minnesota Production Costs increase, with a range from $3.0 million to $13.8 million annually across scenarios.

Q. TABLE 2 OF DR. RAKOW'S REPORT COMPARES THE INTERNAL COST OF MVP PROJECT 3 AND 4 TO THE 161 KV REBUILD ALTERNATIVE, REFLECTING LMP IMPACTS AND CONSTRUCTION COSTS. HAVE YOU PROVIDED A CORRESPONDING TABLE BASED ON MINNESOTA PRODUCTION COSTS INSTEAD OF LMP IMPACTS?

A. Yes. In Table 4A, I have calculated the difference in the internal cost of MVP Project 3 and Project 4 combined and the 161 kV Rebuild Alternative,

[8] Differences in production costs between cases reflect a number of factors, including the reduction in congestion, reduction in (a portion of) transmission line losses and differences in the wind resource supplies.

in which the internal cost of each alternative reflects the annualized construction cost and the change in Minnesota Production Cost. As in prior tables, a negative value indicates that MVP Project 3 and Project 4 combined has greater net benefits than the 161 kV Rebuild Alternative. Under reference assumptions, MVP Project 3 and Project 4 combined provide greater benefits than the 161 kV Rebuild Alternative. When accounting for increases/decreases in construction costs (plus or minus 30 percent), MVP Project 3 and Project 4 has greater net benefits in 7 of 8 scenarios considered. Under sensitivities that assume MVP Project 5 is not in service, the 161 kV Rebuild Alternative generally provides greater net benefits (9 of 12 cases).

In Table 4B, I have calculated the difference between the internal costs of MVP Project 3 alone (without MVP Project 4) and the 161 kV Rebuild Alternative. Under reference assumptions, MVP Project 3 and Project 4 combined provide greater net benefits than the 161 kV Rebuild Alternative. When accounting for increases/decreases in construction costs (plus or minus 30 percent), MVP Project 3 and Project 4 combined has greater net benefits in all scenarios. Under sensitivities that assume MVP Project 5 is not in service, MVP Project 3 has greater net benefits in half of the cases, and the 161 kV Rebuild Alternative has greater net benefits in the other half of the cases.

Q. DOES THE INTERNAL COST METRIC REFLECT ALL COSTS RELEVANT TO MAKING A DECISION BETWEEN ALTERNATIVES?

A. No. As recognized by Dr. Rakow, there are many other factors relevant to a choice among transmission alternatives. One factor is other social costs, such as the externality costs associated with air emissions. In his analysis, Dr. Rakow evaluates the costs associated with changes in emissions due to reductions in transmission line losses.

Q. DID YOU CONSIDER SOCIAL COSTS OTHER THAN PRODUCTION COSTS IN YOUR DIRECT TESTIMONY?

A. Yes. In my direct testimony, I provided estimates of other social costs from the development of MVP Project 3 (with and without MVP Project 4), including costs associated with carbon dioxide (CO_2), nitrogen oxides (NO_X) and mercury emissions. The social costs associated with these emissions were estimated using the externality values that have been adopted by the Minnesota Public Utility Commission ("Commission"). Thus, while Dr. Rakow indicates that ITC Midwest did not provide social cost estimates and should do so in the future, in fact, these values were used as part of the analysis in my direct testimony.[9]

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[9] "ITCM should have used the Commission's externality values. I recommend that the Commission order ITCM to use the Commission's externality values and cost of future CO_2 regulation value in future CN proceedings." Rakow direct testimony, p. 35.

Q. DID DR. RAKOW ADOPT THE ESTIMATES OF OTHER SOCIAL COSTS DEVELOPED IN YOUR DIRECT TESTIMONY?

A. No. Instead of relying on the estimates of other social costs developed in my direct testimony, Dr. Rakow develops his own social cost estimates. In his analysis, Dr. Rakow only considers reductions in emissions associated with the reduction in transmission line losses. His analysis does not account for changes in emissions that occur because of the shifts in power generation across resources within MISO that occur because of the new transmission. These shifts in production occur because of reductions in congestion, reductions in (a portion of) line losses and increases in renewables that can be supported by the system. The estimates of social costs associated with each transmission alternative provided in my testimony account for these shifts in production, which are much larger in magnitude than the changes in emissions from transmission line losses considered by Dr. Rakow.

Q. DO YOU DEVELOP ESTIMATES OF THE SOCIAL COSTS TO MINNESOTA ASSOCIATED WITH EACH ALTERNATIVE?

A. Yes. My analysis of social costs reflects changes in the emissions from electricity production in Minnesota, adjusted for changes in net exports between cases. I refer to these as Minnesota Emission Costs. These estimates differ from those developed in my direct testimony, which reflected the changes in CO_2 emissions across the entire MISO footprint.

Table 5A, 5B and 5C provide estimates of the change in Minnesota Emission Costs from the development of MVP Project 3 and Project 4 combined, MVP Project 3 alone (without MVP Project 4) and the 161 kV Rebuild Alternative, respectively. As shown in Table 5A, under reference assumptions, reductions in Minnesota Emission Costs range from $12.6 million to $17.1 million. When MVP Project 5 is not in service, reductions are lower, ranging from $2.5 million to $6.6 million.

The development of MVP Project 3 alone (without MVP Project 4) results in fewer environmental benefits, as measured by Minnesota Emission Costs. Reductions in these costs range from $5.2 million to $8.1 million with MVP Project 5 in service, while they increase by $1.3 million to $2.9 million when MVP Project 5 is not in service. Similarly, the development of the 161 kV Rebuild Alternative decreases Minnesota Emission Costs when MVP Project 5 is in service (with decreases ranging from $1.0 million to $2.0 million) and increases these costs when it is not in service (with increases ranging from $2.3 million to $3.1 million).

Q. DO YOU USE THE SAME EXTERNALITY VALUE FOR CO_2 AS DR. RAKOW?

A. Yes. We both adopt the externality value for CO_2 that has been approved by the Commission in Docket No. E-999/CI-07-1199.[10]

[10] Minnesota Public Utilities Commission, Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs, Docket No. E-999/CI-07-1199 (Nov. 2, 2012).

Q. DOES DR. RAKOW CONSIDER OTHER ENVIRONMENTAL EMISSIONS?

A. Dr. Rakow considers SO_2 emissions, but does not include these social costs in his calculations. He states that he does not separately account for these costs because the cost of SO_2 credits is internalized within the LMPs that he uses to estimate customer benefits.

Q. IS THIS AN ACCURATE WAY TO ACCOUNT FOR SO_2 EMISSION IMPACTS?

A. Potentially not. LMPs reflect the cost of SO_2 credits that are included in the production costs of the marginal price-setting resources. However, these costs will not necessarily accurately reflect the cost of SO_2 credits for all of the other resources that supply electricity in each hour (that is, the "infra marginal" resources with costs below the marginal price-setting resource). For example, if the marginal resource is an efficient combined cycle gas-fired unit, the SO_2 credits associated with its costs will not accurately reflect the costs for resources with higher emissions (e.g., a coal-fired generation facility) or lower emissions (e.g., a wind turbine). These differences again illustrate the limitations of relying on LMPs for evaluating costs – any impact of SO_2 credits on LMPs is unlikely to represent actual SO_2 credit cost savings. However, a production cost measure, which accounts for SO_2 costs based on estimated changes in SO_2 emissions, provides an accurate accounting of these costs.

Q. DO YOU CONSIDER OTHER ENVIRONMENTAL EMISSIONS THAT ARE NOT CONSIDERED BY DR. RAKOW?

A. Yes. Dr. Rakow does not account for NO_X and mercury emissions, which are included in my analysis. In prior testimony regarding new 345 kV transmission lines in Minnesota, he has accounted for these types of emissions, and others.[11] As described in my direct testimony, these are the two types of emissions I am able to evaluate using data from the PROMOD analysis. Consequently, I include them in my analysis to provide a more complete estimate of emission costs. To the extent that I do not account for other emissions, my estimates of the benefits associated with emission reductions would tend to be conservative.

IV. DR. RAKOW'S ANALYSIS OF OTHER FACTORS

Q. DOES DR. RAKOW CONSIDER FACTORS OTHER THAN THOSE EXPLICITLY INCLUDED IN HIS INTERNAL AND SOCIAL COSTS?

A. Yes. Dr. Rakow performs an assessment of differences in transfer capability between alternatives. His calculations rely on estimates of

[11] Direct Testimony of Dr. Steve Rakow on Behalf of the Minnesota Office of Energy Security, Docket No. ET2,E002, et al./CN-06-1115, May 23, 2008. In this testimony, Dr. Rakow considers additional emissions that are not quantitatively evaluated in my analysis, including PM_{10}, CO and lead. To the extent that these emissions tend to be correlated with other emissions considered in my analysis, exclusion of these emissions from my analysis would tend to understate the emission impacts of the new transmission infrastructure.

transfer capability developed in Appendix J of the Application.[12] In his analysis, he calculates the cost-effectiveness of each alternative in terms of cost per MW of transfer capability, and compares the cost-effectiveness of transfer capability provided by the 161 kV Rebuild Alternative to the cost-effectiveness of incremental transfer capability provided by MVP Project 3 and 4 beyond the amount provided by the 161 kV Rebuild Alternative.

Q. IS THIS A REASONABLE APPROACH TO CONSIDERING THE IMPACT OF OTHER FACTORS IN THE CONTEXT OF DR. RAKOW'S ANALYSIS OF INTERNAL AND SOCIAL COSTS?

A. No. Dr. Rakow's report concludes that "it does not appear that the incremental transfer capability of MVP Project 3 plus MVP Project 4 above that provided by the 161 kV Rebuild Alternative is reasonably priced."[13] However, within the context of the assessment of internal and social costs performed by Dr. Rakow, which calculates the net benefits associated with each alternative, the "price" paid for one particular type of benefit – in this case, transfer capability – is irrelevant. Instead, Dr. Rakow should explicitly integrate these benefits into his numerical assessment of social costs or qualitatively assess how this incremental benefit, which may be difficult to measure on a common dollar metric, affects the relative benefits provided by across alternatives.

[12] ITCM, "ITC Midwest LLC Multi-Value Project #3 Planning Study," Jeff Eddy, Joseph Berry, March 22, 2013.

[13] Rakow direct testimony, p. 43.

Q. CAN YOU ILLUSTRATE THE FLAW IN HIS APPROACH?

A. Yes. The example provided below in Table 6 illustrates why Dr. Rakow's approach can lead to misleading conclusions. Table 1 compares two hypothetical projects that provide two types of benefits – "Benefit I" and "Benefit II". Consider first the costs and Benefit I only – this situation is analogous to Dr. Rakow's comparison of project construction costs and LMP impacts. Suppose that Project A has a cost of $100 and a dollar value of Benefit 1 equal to $110. In this case, Project A leads to net benefits of $10. Project B, with a cost of $10 and benefits from Benefit I equal to $20, also has a net benefit of $10. Thus, in terms of costs and Benefit I, both projects provide the same net benefits and one project is not preferred to the other.

Table 6: Illustration of Flaws in Dr. Rakow's Assessment of Other Factors

	Alternatives	
	A	**B**
Cost	$100	$10
Benefit I (e.g., production cost changes)	$110	$20
Benefit II (e.g., transfer capability) in quantity	$200	$100
Benefit II (e.g., transfer capability) in dollars	$20	$10
Net Benefits		
Benefit I - Cost	$10	$10
Benefit I + Benefit II - Cost	$30	$20
Incremental Cost Effectiveness		
Ratio of Benefit II (in quantity) to Cost		10.0
Ratio of Incremental Benefit II (in quantity) to Incremental Cost	1.1	

To this point, this assessment does not consider all benefits associated with each project because it excludes the benefits associated with Benefit II, which are analogous to the increases in transfer capability considered by Dr. Rakow. From an economic standpoint, the proper approach to selecting between projects is to choose the project that provides the greatest net benefits. Based on the example in Table 6, Project A would be preferred to Project B because after accounting for the dollar value of Benefit II, Project A has greater net benefits than Project B ($30 for Project A versus $20 for Project B).

However, even without dollar valuations, as is the case with Dr. Rakow's assessment of increases in transfer capability, one could reach a conclusion about which project is preferred. Because the Project A provides a greater quantity of Benefit II than Project B and the two projects otherwise have the same net benefits, Project A would be preferred to Project B.

By contrast, Dr. Rakow's approach leads to the incorrect conclusion that Project B would be preferred to Project A. Instead of aggregating all benefits and costs, Dr. Rakow estimates the incremental cost-effectiveness or "price" of each option and suggests that this metric provides information relevant to the choice between the two alternatives. Based on the values in Table 6, Dr. Rakow's metric suggests that Project B would provide 10 units of Benefit II for each dollar, while Project A would provide only 1.1 units of Benefits II (beyond that provided by Project B) for each dollar (beyond the cost of Project B). Thus, Dr. Rakow's metric would imply that Project B is preferred, which is the incorrect conclusion.

Q. WHAT ARE THE IMPLICATIONS OF DIFFERENCES OF TRANSFER CAPABILITY FOR THE CHOICE BETWEEN TRANSMISSION ALTERNATIVES?

A. Within the context of Dr. Rakow's cost analysis, the conclusion that MVP Project 3 (with or without Project 4) provides greater transfer capability than the 161 kV Rebuild Alternative should have led Dr. Rakow to the conclusion that, all things being equal, MVP Project 3 is preferred to the 161 kV Rebuild Alternative because of the greater transfer capability it provides. Having accounted for costs in the calculation of internal and social costs, there is no need to account for those costs again when weighing how differences in transfer capability affect the choice between alternatives.

Q. DO YOU HAVE OTHER CONCERNS WITH THE APPROACH USED BY DR. RAKOW TO EVALUATE TRANSFER CAPABILITY?

A. Yes. The metric of transfer capability used by Dr. Rakow is not measured under the same counterfactual assumptions as his analysis of LMP impacts. In Dr. Rakow's analysis, LMP impacts are estimated under the assumption that all MVPs (other than Project 5 in some cases) are in service. By contrast, the estimates of transfer capability he relies on are based on analysis in which only certain MVPs are in service.[14] Thus, he does not evaluate impacts under a consistent set of assumptions.

Q. ARE THERE OTHER MEASURES AVAILABLE THAT REFLECT TRANSMISSION CAPABILITY THAT DR. RAKOW COULD HAVE UTILIZED?

A. Yes. Table A3 in my November 2013 report provides estimates of the minimum quantity of wind power that would need to be curtailed (from the total wind resources supported by the full MVP portfolio) to avoid certain reliability problems. These estimates were developed through analyses performed by ITC Midwest, based on methodologies developed by MISO.

Using these values, I have calculated an estimate of the quantity of wind resources that each transmission alternative helps to reliably support. These estimates, reported in Table 7, reflect the difference between the curtailments in each case relative to the curtailment in the appropriate base case. For example, the quantity of wind resources supported by the 161 kV Rebuild Alternative with MVP Project 5 in service (258 MW) reflects the difference between the wind curtailments with the 161 kV Rebuild Alternative in service (872 MW), and curtailment in the base case (with MVP Project 3 and Project 4 out of service) (1,130 MW). Similar to the

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[14] These include MVP Project 1, Big Stone – Brookings Project, MVP Project 2, the Brookings County – Hampton Project, MVP Project 6, Ellendale – Big Stone Project, and MVP Project 13, the Michigan Thumb Loop Expansion.

estimates of transfer capability relied on by Dr. Rakow, these estimates provide information regarding the relative ability of the transmission alternatives to support the reliable power delivery.

Q. ARE THE ESTIMATES OF THE QUANTITY OF SUPPORTED WIND RESOURCES IN TABLE 7 DEVELOPED UNDER COMPARABLE ASSUMPTIONS TO THE LMP VALUES USED BY DR. RAKOW?

A. Yes. The information summarized in Table A3 was developed as an input to my PROMOD analysis. Thus, for each of the Minnesota Avg LMP change estimates relied on by Dr. Rakow, there is a corresponding estimate of wind curtailment in Table A3 and supported wind resources in Table 7 developed under the same assumptions about transmission infrastructure (that is, which MVPs are in service).

Table 7: Estimates of Transmission Benefits Provided by Alternatives

	Supported Wind Resources (MW) (Schedule 2, Table A3)		Transfer Capability (MW) (Application Appendix J)	
Description	**With MVP 5 In Service**	**With MVP 5 Not In Service**	**Summer Shoulder**	**Summer Peak**
MVP 3 and 4 In Service	1,130	865	1,193	2,320
MVP3 In Service, MVP 4 Not in Service	441	686	736	2,189
161 kV Rebuild, MVP 3 and MVP 4 Not In Service	258	82	463	1,976

Q. HOW DO ESTIMATES OF SUPPORTED WIND RESOURCES COMPARE TO THE ESTIMATES OF TRANSFER CAPABILITY RELIED ON BY DR. RAKOW?

A. Along with the estimates of wind resources supported by the transmission alternatives (incremental to those supported by other MVP elements),

Table 7 also includes the average of the transfer capability across the six estimates (reflecting variations in the source and sink for power supply) reported by Dr. Rakow (and provided in Appendix J of the Application).[15] As shown in the table, the transmission benefit of MVP Project 3 (with or without MVP Project 4) relative to that of the 161 kV Rebuild Alternative is proportionately larger when measured by the quantity of wind resources supported, rather than transfer capability. Thus, the estimates of wind resources supported indicate that MVP Project 3 provides greater transmission benefits relative to the 161 kV Rebuild Alternative than the metric relied on by Dr. Rakow. The difference is particularly dramatic for the Summer Peak transfer capability case. In this case, the 161 kV Rebuild Alternative provides 85 to 90 percent of the transfer capability provided by MVP Project 3 (with or without MVP Project 4). By contrast, when measured in terms of wind resources supported, the transmission benefits provided by the 161 kV Rebuild Alternative is as little as 9 percent and at most 59 percent of that provided by MVP Project 3. To the extent that these transmission metrics both provide useful information about the expected benefits of transmission alternatives, Dr. Rakow should expand his assessment to include consideration of the estimates of wind resources supported by transmission alternatives (derived from the estimates of wind curtailments) that are provided in my testimony, as these figures

[15] These cases reflect variations in the source and sink for power supply, including three sources (reflecting different geographic locations for wind resources on Buffalo Ridge) and two sinks (Minnesota and MISO).

provide different conclusions about the relative merits of transmission alternatives.

Q. ARE THERE OTHER FACTORS THAT WOULD DIFFERENTIATE MVP PROJECT 3 FROM THE 161 KV REBUILD ALTERNATIVE THAT ARE NOT CONSIDERED BY DR. RAKOW?

A. Yes. Dr. Rakow's assessment does not consider many other factors that could differentiate MVP Project 3 from the 161 kV Rebuild Alternative. The LMP impacts he considers account for the cost of the energy itself, but not other services needed to maintain reliable electricity supply. New transmission can lower the cost of supplying capacity, reserves and other ancillary services needed to maintain reliable supply through reductions in the requirements for these services. When new transmission reduces congestion, requirements can potentially be reduced because MISO can rely on the delivery of more-distant resources to help meet load at all times (that is, ensure resource adequacy), respond to system contingencies (reserves) and otherwise maintain a stable system (e.g., voltage regulation). Reductions in transmission energy losses can also reduce resource adequacy (capacity) requirements because fewer resources are required to meet the combination of load plus losses during peak demand hours. Reductions in congestion can also provide other market benefits, such as increased competition and market liquidity. Further, he does not account for other reliability and transmission benefits, which are addressed by Mr. Berry.

In general, these cost changes tend to be proportional to changes in congestion, energy losses and other measures of transmission system performance. To the extent that MVP Project 3 (without or without MVP Project 4) performs better along these metrics than the 161 kV Rebuild Alternative, it would be reasonable to expect that consideration of these other factors would tend to further support the conclusion that MVP Project 3 provides greater net benefits than the 161 kV Rebuild Alternative.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

6141453

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013
Extension granted to Nov. 31, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[X] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
11	**Subject: Forecasting** **Please provide, at a high level, what impact failure to construct MVP4, MVP5, and both projects, would have on Minnesota LMPs, and the cost and benefits associated with MVP3.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	The Certificate of Need Application, Appendices M and N provide information regarding the Minnesota LMP impact if MVP 3 and 4 were constructed and if MVP 3 were constructed, but not MVP 4. ITC Midwest has not prepared an analysis of how the Minnesota LMP would be affected if MVP 5 or any other MVP were not constructed. Additional studies to examine the impact on Minnesota LMPs if MVP 5 is not constructed or both MVP 4 and MVP 5 are not constructed will be performed and a response detailing those impacts will be submitted after these studies are completed. ITC Midwest estimates it can provide this information by November 1, 2013.
Supplemental Answer	Data responsive to this request is provided in the LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis, **Attachment 11-1**.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis

Rodney Frame
Todd Schatzki

Analysis Group

November 2013

LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis

Rodney Frame
Todd Schatzki

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 Midcontinent Independent System Operator, Inc.'s (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 and production costs (in MISO) from implementing the Project (and other components of MVPs 3 and 4) and a 161 kV Rebuild alternative. Analyses are performed with and without MVP 5, which includes new transmission lines and associated facilities in south western Wisconsin. Impacts are evaluated under two future electricity demand scenarios: Business as Usual: Low Demand (hereafter, Low Demand) and Business as Usual: High Demand (hereafter, High Demand). These analyses are performed in response to Utility Information Requests made by the Department of Commerce, Division of Energy Resources (DER). The analyses have been performed using wind curtailment estimates developed by ITC Midwest.

The development of MVPs 3 and 4 lowers average LMPs for Minnesota by $0.48 per MWh (1.7%) in 2021 and $0.68 per MWh (2.1%) in 2026 under the Low Demand scenario. Price reductions are similar under the High Demand scenario: $0.52 per MWh (1.5%) in 2021 and $0.55 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 Low Demand) to $52.4 million (2026 Low Demand).

The development of MVP 3 alone, without the development of MVP 4, results in smaller LMP reductions. In 2021, LMPs fall by $0.06 per MWh (0.2%) under both Low Demand and High Demand scenarios. In 2026, LMPs are effectively unchanged with the development of MVP 3 alone without MVP 4. These LMP changes result in annual reductions in wholesale energy payments for Minnesota load that range from $0.9 million (2026 High Demand) to $4.6 million (2021 Low Demand).

LMP reductions from the implementation of MVPs 3 and 4 are 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 alone, without MVP 4, are varied, with LMPs rising in some areas and falling in others.

Development of MVPs 3 and 4 also lowers production costs for the entire MISO footprint. Reductions in production costs range from $114.9 million to $185.6 million across scenarios and years when both MVPs 3 and 4 are developed, and range from $35.2 million to $49.5 million when only MVP 3 is developed.

Results are sensitive to the development of MVP 5, which is assumed to take place for the results reported above. If MVP 5 is not developed, LMP reductions from development of MVP 3 and 4 (together, or MVP 3 alone) are smaller than they otherwise would be. For example, the LMP reductions from development of both MVP 3 and 4 would be 7% to 43% lower if MVP 5 were not developed in

comparison to the case where it is developed. Production cost reductions from development of both MVP 3 and 4 are similar whether or not MVP 5 is developed, ranging from $95.3 to $185.6 million. However, production cost reductions from development of MVP 3 alone, which range from $35.2 million to $82.4 million across demand scenarios and years, are greater if MVP 5 is not developed.

Development of the 161 kV Rebuild alternative (without MVPs 3 and 4) reduces LMPs by $0.17 per MWh (0.6%) in 2021 and $0.32 per MWh (1.0%) in 2026 under the Low Demand scenario if MVP 5 is constructed. Price reductions are similar under the High Demand scenario: $0.35 per MWh (1.0%) in 2021 and $0.32 per MWh (0.7%) in 2026. However, if MVP 5 is not constructed, these price reductions are lower, ranging from $0.06 per MWh (0.1%) to $0.15 per MWh (0.4%). Reductions in production costs range from $16.3 million to $23.7 million if MVP 5 is developed. If MVP 5 is not developed, the 161 kV Rebuild results in higher production costs in three of four scenario/study year combinations evaluated.

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

Rodney Frame
Todd Schatzki

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. These facilities include the Minnesota – Iowa 345 kV Transmission Project (the Project), which is being developed as part of the Midcontinent Independent 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] 133 FERC ¶ 61,221(2010), at P 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)[4] 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. 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.[5] The Project, together with other facilities being proposed by MidAmerican Energy Company (MidAmerican) to be constructed in Iowa [6] 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.[7] 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.

[3] Midwest Independent Transmission System Operator, Inc., 133 FERC ¶ 61,221(2010), p. 3 (Dec. 16, 2010 Order).

[4] https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20 Analysis%20Full%20Report.pdf

[5] 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, both of which will be in Kossuth County, Iowa. The expected total cost of the Project is approximately $271 to $283 million (plus or minus 30 percent.) Details on these expected costs, the route taken by the Project, and new and modified changes to substations and transformers, are provided in Chapter 2 of: ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Minnesota-Iowa 345 kV Transmission Project in Jackson, Martin and Faribault Counties, Docket No. ET6675/CN-12-1053, March 22, 2013.

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

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

This report supplements previous analyses that have been developed and responds to Utility Information requests of the Department of Commerce, Division of Energy Resources (DER).[8] These requests include:

1. Information on the impacts of the failure to construct MVP 4, MVP 5 and both projects; and
2. Information on the economic impacts of alternatives identified in the MVP Planning Study.

The MVP Planning Study,[9] performed by ITC Midwest and included in its application for a Certificate of Need for the Project, evaluates the reliability impacts of transmission alternatives on ITC Midwest's system in Minnesota. In this study, ITC Midwest considered a transmission alternative, referred to herein as the 161 kV Rebuild, that is evaluated in the current report.[10] With the 161 kV Rebuild, the existing transmission line from Fox Lake-Rutland-Winnebago Junction, that has been a main constraint on the electrical system in the region, would be rebuilt. This rebuild would include new structures and lines, and would increase the line's rating from 168 MVA to 446 MVA. As requested by the DER, the analyses described herein include evaluations of the 161 kV Rebuild, in addition to analyses of MVP 3 and 4.

This Second Supplemental Report differs from prior analyses we have prepared (referred to as the March 2013 Analysis and the April 2013 Analysis)[11] in the following two ways: (i) the Second Supplemental Report develops price impacts and changes in production costs for the 161 kV Alternative, which was not considered in either earlier analysis; and (2) the Second Supplemental Report considers the impacts of alternative transmission infrastructure for Minnesota when MVP 5 is not in service, whereas both earlier analyses assumed that MVP 5 was in service in all cases evaluated.

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, and the 161 kV Rebuild. 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, and transmission system topology and limits. Among other things,

[8] Department of Commerce, Division of Energy Resources, Utility Information Requests No. 11 and 13, August 13, 2013.

[9] Jeff Eddy and Joseph Berry, "ITC Midwest LLC, Multi-Value Project #3 Planning Study," Appendix J, Application of ITC Midwest for a Certificate of Need for the Minnesota-Iowa 345 k V Transmission Project, March 22, 2013.

[10] This study also considered a "No Build" alternative, under which no new transmission is built. This alternative is the same as our Base Case, and therefore serves as the baseline against which other cases are compared.

[11] Frame, Rodney, Todd Schatzki, Pavel Darling, "LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis," April 2013; Frame, Rodney, Todd Schatzki, Pavel Darling, "LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project," March 2013.

PROMOD allows the estimation of time-varying locational marginal energy prices (LMPs)[12] 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.

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 (referred to as "average LMPs"). These average LMPs were determined both for Minnesota taken as a whole (sometimes hereafter referred to as the "Minnesota Avg LMP") and for each of the eight individual Minnesota load-serving entities (LSEs) that are represented in the PROMOD database.[13] Appendix A provides further detail on these computations.

The PROMOD analysis uses two alternative "base cases". In one base case (Base Case), all 17 projects in the MVP portfolio except MVPs 3 and 4 are assumed to be in service. In the second base case (No MVP 5 Base Case), all 17 projects in the MVP portfolio except MVPs 3, 4 *and 5* are assumed to be in service. Changes in average LMPs and the Minnesota Avg LMP – together or separately sometimes referred to as "LMP impacts" – are calculated between each base case and three "study cases". A summary of these base and study cases is provided in Table 1.

In Study Case 1, all 17 MVPs are assumed to be in service. The difference between the average LMPs without MVPs 3 and 4 in service (Base Case) and the average LMPs with MVPs 3 and 4 in service (Study Case 1) then represents the LMP impact 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.

In Study Case 2, MVP 3 is assumed to be placed in service, but MVP 4 is not. The LMP impacts in this case provide one measure of the incremental impact of MVP 3.[14] For example, the difference

[12] In MISO, electric energy 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.

[13] These eight Minnesota LSEs are Alliant West—Interstate Power & Light, Dairyland Power Cooperative (Dairyland), 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 (SMMPA). 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.

[14] Hypothetically, 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 in fact still would be constructed. However, we understand that MVP 4 would not be developed without MVP 3. Thus, we have not analyzed PROMOD cases that assume the construction of MVP 4 but not MVP 3.

between the average LMP without MVPs 3 and 4 (Base Case) and the average LMP with MVP 3, but not MVP 4 (Study Case 2) represents the LMP impact from implementing MVP 3 alone, as compared to the Base Case without both MVPs 3 and 4.

Study Case 3 assumes that the 161 kV Rebuild is placed in service instead of MVP 3, and also that MVP 4 is not in service. The difference in average LMPs between the Base Case and Study Case 3 represents the impact of the 161 kV Rebuild.

Table 1

Base Cases and Study Cases Considered

<u>With MVP 5 In Service</u> **Base Case** • MVP 3 & 4 Not In Service (Base Case) **Study Cases** • MVP 3 & 4 In Service (Study Case 1) • MVP 3 In Service, MVP 4 Not in Service (Study Case 2) • 161 kV Rebuild, MVP 3 and 4 Not In Service (Study Case 3)
<u>With MVP 5 Not In Service</u> **Base Case** • MVP 3, 4 & 5 Not In Service (No MVP 5 Base Case) **Study Cases** • MVP 3 & 4 In Service, MVP 5 Not In Service (Study Case 4) • MVP 3 In Service, MVP 4 & 5 Not in Service (Study Case 5) • 161 kV Rebuild, MVP 3, 4 & 5 Not In Service (Study Case 6)

Note: MVPs 1, 2 and 6-17 are assumed to be in service in all base cases and study cases.

The LMP impacts and changes in wholesale market energy payments calculated relative to the Base Case assume that MVP 5 is in service. We also calculate the impacts of these transmission projects under the assumption that MVP 5 is not in service. These estimates are calculated by comparing a Base Case with MVPs 3, 4 and 5 not in service – which is referred to as the No MVP 5 Base Case – to study cases with the relevant project elements in service. For example, the LMP impact of MVPs 3 and 4 without MVP 5 in service is based on the difference between the load-weighted average electric energy prices in No MVP 5 Base Case and the load-weighted average electric energy prices with MVPs 3 and 4 in service, but MVP 5 not in service (Study Case 4). Analogous calculations are performed to estimate the impacts of MVP 3 alone (Study Case 5), and the 161 kV Rebuild (Study Case 6).

The PROMOD analysis quantifies the lower wholesale electric *energy* prices that will result from MVPs 3 and 4 and the 161 kV Rebuild, but it does not quantify other potential wholesale electricity price benefits such as lower operating reserve costs and lower capacity requirements and prices. Consequently, focusing solely on the change in wholesale electric energy prices from the PROMOD analysis potentially will understate the full range of price benefits that can be expected from MVPs 3 and 4 or the 161 kV Rebuild.

In addition to the LMP comparisons, the PROMOD analysis that we have conducted also estimates the production costs of meeting MISO load (referred to herein as MISO Production Costs), and develops similar comparisons between cases as those described above for the LMP comparisons. What we refer to as MISO Production Costs are 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 load growth scenarios for each year. These scenarios, which were also used in the MISO MVP Report, are as follows:

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

The geographic region covered by the PROMOD analysis includes a large portion of the Eastern Interconnection,[15] including all of MISO and the footprint of the adjacent PJM Interconnection and other directly and indirectly interconnected systems.

The PROMOD analysis relies largely on the same data used by MISO in its economic analysis of the MVP portfolio. 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 the changes to transmission (*i.e*., MVPs 3, 4 and 5, and the 161 kV Rebuild), the only difference between the study cases and the base case is the quantity of wind power assumed. The quantity of wind power resources is reduced from the base case based because fewer wind resources can be reliably supported without elements of the MVP portfolio, as proposed. As discussed more fully in Appendix A, estimates of the quantity of wind power that can be reliably supported under different transmission configurations have been developed by ITC using the same methodology that MISO used in the MISO MVP Report.

[15] 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.

3. RESULTS

A. LOCATIONAL MARGINAL PRICE

I. MVPS 3 AND 4

The LMP impacts arising from MVPs 3 and 4 are reported in Tables 2 to 4. Table 2 shows the Minnesota Avg LMPs for each of the cases and scenarios evaluated. Tables 3 (Low Demand) and 4 (High Demand) then provide the results for the individual Minnesota LSEs. 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.

We first consider results when MVP 5 is in service. These are the comparisons between the Base Case as defined above, and Study Cases 1, 2 and 3. In 2021, under the Low Demand scenario, the Minnesota Avg LMP is $28.44 without MVPs 3 and 4 in service (*i.e.*, the Base Case) and $27.96 with both MVPs 3 and 4 in service (*i.e.*, Study Case 1). The results indicate a Minnesota Avg LMP reduction of $0.48 per MWh from the implementation of both MVPs 3 and 4, or 1.7%. Under the High Demand scenario, the Minnesota Avg LMP in 2021 is reduced by $0.52 per MWh from the implementation of both MVPs 3 and 4, or 1.5%. When the Minnesota Avg 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 in 2021 under Low Demand to $52.5 million in 2026 under Low Demand.

Development of MVP 3 alone without MVP 4 (Study Case 2) results in smaller LMP reductions, as shown in columns [F] and [G] of Table 2. In 2021, under Low Demand, the Minnesota Avg LMP is $28.38 per MWh in Study Case 2 as compared to $28.44 per MWh in the Base Case. Thus, the Minnesota Avg LMP falls by $0.06 per MWh (0.2%) with the introduction of MVP 3 but not MVP 4. With High Demand in 2021, the price reduction from development of MVP 3 is $0.06 (0.2%). The resulting decrease in annual wholesale energy payments in 2021 is $4.6 million under Low Demand and $4.3 million under High Demand.

The lower panel of Table 2, along with Tables 3B and 4B, report LMP impacts when it is assumed that MVP 5 is not developed. Across the scenarios and years evaluated, Minnesota Avg LMPs are higher when MVP 5 is in service compared to when it is not in service. For example, under Low Demand in 2021, the Minnesota Avg LMP increases from $27.96 per MWh with all MVPs in service (Study Case 1) to $28.85 per MWh with all MVPs except MVP 5 in service (Study Case 4).

The LMP reductions from MVPs 3 and 4 together, and MVP 3 alone, are lower when MVP 5 is not developed. For example, with MVP 5 not in service, development of MVP 3 and 4 results in change in Minnesota Avg LMP of $0.36 per MWh (Low Demand in 2021), while with MVP 5 in service, the impact of MVP 3 and 4 is $0.48 per MWh.

Table 3 reports, for the Low Demand scenario, the load weighted average LMPs for each Minnesota LSE with and without MVPs 3 and 4. Table 4 reports similar figures for the High Demand scenario. The LMP impacts vary across companies but generally show significant price decreases for all LSEs across study years and demand scenarios after the inclusion of both MVPs 3 and 4. The principal exception is Dairyland, which has about 12 percent of its load in Minnesota. Dairyland experiences a price increase in both scenarios in 2026, but not in 2021. With MVP 5 in service, the largest (beneficial) price impacts are for SMMPA, where the average LMP is $26.55 with MVPs 3 and 4 in service, and $27.54 without MVPs 3 and 4 in service. Thus, the effect of MVPs 3 and 4 is to lower SMMPA's average LMP by $0.99, or 3.6%, in 2021. (The effects are similar for the High Demand scenario shown in Table 4.) The smallest price impacts are for Dairyland. For Dairyland, in 2021 under Low Demand, the effect of implementing MVPs 3 and 4 is to lower Dairyland's average LMP by $0.19, or 0.6%.

When developing only MVP 3, compared to a case in which neither MVP 3 nor 4 are developed, LMP impacts vary widely across Minnesota LSEs, with LMPs falling in some LSEs and rising in others. When MVP 5 is not in service, LMP impacts (reductions) for individual LSEs in most instances are larger compared to when MVP 5 is in service.

II. 161 KV REBUILD

The LMP impacts arising from the 161 kV Rebuild are reported in Tables 5 to 7. Table 5 shows the LMP impacts in each of the study years for Minnesota taken as a whole. Table 6 reports the LMP impacts for each Minnesota LSE for the Low Demand scenario, while Table 7 reports similar figures for the High Demand scenario.

In 2021 under Low Demand, the Minnesota Avg LMP is $28.27 per MWh with the 161 kV Rebuild (but not MVP 4) (Study Case 3) as compared to $28.44 per MWh without both MVPs 3 and 4 (Base Case). Thus, the Minnesota Avg LMP falls by $0.17 per MWh (0.6%) with the introduction of the 161 kV Rebuild (and without MVPs 3 and 4). The price reduction from the 161 kV Rebuild in 2021 under High Demand is $0.35 (1.0%). The resulting decrease in annual wholesale energy payments for 2021 is $12.5 million under Low Demand and $27.6 million under High Demand.

The price effects vary across LSEs. With MVP 5 in service, the addition of the 161 kV Rebuild generally reduces price for all LSEs across study years and demand scenarios. As shown in Table 6, the largest (beneficial) price impacts are for SMMPA, while the smallest price impacts are for Alliant West. When MVP 5 is not in service, LMP impacts (reductions) from the 161 kV Rebuild are generally smaller for individual LSEs compared to LMP impacts when MVP 5 is in service.

B. PRODUCTION COSTS

I. MVPS 3 AND 4

The estimated changes in MISO Production Costs resulting from MVPs 3 and 4 are provided in Table 8 and 9. Table 8 reports the change in total annual MISO Production Costs, while Table 9 reports the average change in production costs per MWh of load. With MVP 5 in service, in 2021 under a Low Demand scenario, annual MISO Production Costs are $13,217 million with both MVPs 3 and 4 (Study Case 1) and $13,332 without MVPs 3 and 4 (Base Case). Thus, the development of MVPs 3 and 4 reduces annual MISO Production Costs by $114.9 million, or 0.9%. In 2026, the analogous reduction is $136.9 million or 0.9%. Decreases in production costs arising from development of both MVPs 3 and 4 under the High Demand scenario are somewhat higher: $132.2 million (0.8%) in 2021 and $185.6 million (0.9%) in 2026.

With MVP 5 not developed, MISO Production Costs are higher across all years and demand scenarios compared to when MVP 5 is developed. The reductions in MISO Production Costs, based on the different study case-base-case comparisons, are similar whether or not MVP 5 is developed. Except for the Low Demand scenario in 2021, MISO Production Cost impacts are within $10 million annually with and without MVP 5.

The reductions in MISO Production Costs from developing MVP 3, but not MVP 4, are reported in columns [F] and [G] of Table 9. With MVP 5 in service, under the Low Demand scenario, the development of MVP 3 without MVP 4 reduces annual MISO Production Costs by $42.9 million in 2021 (0.3% of total production costs), and $35.2 million (0.2%) in 2026. Reductions in MISO Production Costs from introducing MVP 3 without MVP 4 are higher when MVP 5 is not in service – for example, under Low Demand, MISO Productions Costs fall by $65.4 million (0.5%) with MVP 5 not in service, as compared to $42.9 million with MVP 5 in service, a difference of 52%.

II. 161 KV REBUILD ALTERNATIVE

The estimated changes in MISO Production Costs resulting from the 161 kV Rebuild are provided in Tables 10 and 11. Table 10 reports the change in annual MISO Production Costs, while Table 11 reports the average change in MISO Production Costs per MWh. With MVP 5 in service, reductions in MISO Production Costs range from $16.3 to $23.7 million (0.1% of total production costs) across the study years and demand scenarios considered. With MVP 5 not in service, changes MISO Production Costs range from a decrease of $7.5 million to an increase in $10.2 million.

Table 2
LMP Changes From MVPs 3 and 4
Minnesota Avg LMP

With MVP 5

	Year	Load Weighted Average LMP ($ per MWh): Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	Average LMP Change: LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$27.96	$28.38	$28.44	-$0.48	-1.7%	-$0.06	-0.2%
Low Demand	2026	$31.17	$31.84	$31.85	-$0.68	-2.1%	-$0.01	0.0%
Business as Usual:	2021	$34.50	$34.96	$35.02	-$0.52	-1.5%	-$0.06	-0.2%
High Demand	2026	$45.09	$45.62	$45.64	-$0.55	-1.2%	-$0.02	-0.1%

Without MVP 5

	Year	Load Weighted Average LMP ($ per MWh): Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	Average LMP Change: LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$28.85	$29.18	$29.21	-$0.36	-1.2%	-$0.02	-0.1%
Low Demand	2026	$32.10	$32.63	$32.58	-$0.48	-1.5%	$0.06	0.2%
Business as Usual:	2021	$35.26	$35.70	$35.74	-$0.48	-1.3%	-$0.04	-0.1%
High Demand	2026	$46.26	$46.69	$46.57	-$0.31	-0.7%	$0.11	0.2%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.
[2] Minnesota Avg LMP is the load weighted average LMP for Minnesota, calculated as described in Appendix A.

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

			With MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$29.08	$29.65	$29.43	-$0.35	-1.2%	$0.22	0.8%
		2026	$33.07	$33.49	$33.28	-$0.21	-0.6%	$0.22	0.7%
Dairyland Power Cooperative	11.5%	2021	$30.97	$32.72	$31.16	-$0.19	-0.6%	$1.56	5.0%
		2026	$35.54	$37.57	$35.31	$0.23	0.6%	$2.26	6.4%
Great River Energy	99.6%	2021	$27.47	$27.71	$28.00	-$0.53	-1.9%	-$0.29	-1.0%
		2026	$29.84	$30.29	$30.58	-$0.74	-2.4%	-$0.29	-1.0%
Minnesota Power and Light Company	100.0%	2021	$28.23	$28.50	$28.63	-$0.40	-1.4%	-$0.13	-0.4%
		2026	$31.43	$31.88	$32.02	-$0.58	-1.8%	-$0.14	-0.4%
Minnkota Power Coop	45.1%	2021	$30.22	$30.41	$30.65	-$0.43	-1.4%	-$0.24	-0.8%
		2026	$34.47	$34.75	$35.18	-$0.72	-2.0%	-$0.44	-1.2%
Northern States Power Company	74.8%	2021	$27.92	$28.32	$28.39	-$0.47	-1.7%	-$0.06	-0.2%
		2026	$31.47	$32.14	$32.16	-$0.69	-2.2%	-$0.02	-0.1%
Otter Tail Power Company	48.4%	2021	$28.54	$28.62	$28.95	-$0.41	-1.4%	-$0.33	-1.1%
		2026	$31.04	$31.20	$31.65	-$0.61	-1.9%	-$0.45	-1.4%
Southern Minnesota Municipal Power Agency	100.0%	2021	$26.55	$28.67	$27.54	-$0.99	-3.6%	$1.13	4.1%
		2026	$28.64	$31.57	$29.58	-$0.94	-3.2%	$1.99	6.7%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

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

			Without MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$29.32	$30.29	$30.17	-$0.85	-2.8%	$0.11	0.4%
		2026	$33.25	$34.43	$34.00	-$0.75	-2.2%	$0.43	1.3%
Dairyland Power Cooperative	11.5%	2021	$31.25	$33.25	$31.62	-$0.37	-1.2%	$1.63	5.1%
		2026	$35.83	$37.93	$35.58	$0.25	0.7%	$2.35	6.6%
Great River Energy	99.6%	2021	$28.51	$28.59	$28.85	-$0.34	-1.2%	-$0.26	-0.9%
		2026	$30.92	$31.19	$31.44	-$0.52	-1.7%	-$0.25	-0.8%
Minnesota Power and Light Company	100.0%	2021	$29.01	$29.18	$29.31	-$0.31	-1.1%	-$0.13	-0.5%
		2026	$32.24	$32.61	$32.72	-$0.47	-1.4%	-$0.10	-0.3%
Minnkota Power Coop	45.1%	2021	$30.97	$30.97	$31.27	-$0.30	-1.0%	-$0.29	-0.9%
		2026	$35.40	$35.57	$36.07	-$0.67	-1.9%	-$0.50	-1.4%
Northern States Power Company	74.8%	2021	$28.75	$29.08	$29.10	-$0.35	-1.2%	-$0.02	-0.1%
		2026	$32.30	$32.83	$32.76	-$0.46	-1.4%	$0.07	0.2%
Otter Tail Power Company	48.4%	2021	$29.63	$29.51	$29.88	-$0.25	-0.8%	-$0.37	-1.2%
		2026	$32.06	$32.09	$32.62	-$0.56	-1.7%	-$0.53	-1.6%
Southern Minnesota Municipal Power Agency	100.0%	2021	$28.21	$30.46	$28.98	-$0.77	-2.7%	$1.48	5.1%
		2026	$30.84	$33.42	$31.31	-$0.47	-1.5%	$2.11	6.8%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

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

			With MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$32.39	$33.39	$33.24	-$0.84	-2.5%	$0.15	0.5%
		2026	$39.44	$40.85	$40.45	-$1.01	-2.5%	$0.40	1.0%
Dairyland Power Cooperative	11.5%	2021	$36.06	$38.16	$36.39	-$0.34	-0.9%	$1.77	4.9%
		2026	$44.69	$47.07	$44.18	$0.51	1.2%	$2.90	6.6%
Great River Energy	99.6%	2021	$33.60	$33.84	$34.21	-$0.61	-1.8%	-$0.37	-1.1%
		2026	$42.34	$42.70	$42.99	-$0.64	-1.5%	-$0.29	-0.7%
Minnesota Power and Light Company	100.0%	2021	$33.77	$34.13	$34.28	-$0.51	-1.5%	-$0.16	-0.5%
		2026	$41.95	$42.39	$42.37	-$0.42	-1.0%	$0.02	0.1%
Minnkota Power Coop	45.1%	2021	$36.01	$36.15	$36.57	-$0.56	-1.5%	-$0.41	-1.1%
		2026	$44.71	$44.95	$45.43	-$0.72	-1.6%	-$0.48	-1.1%
Northern States Power Company	74.8%	2021	$35.24	$35.65	$35.66	-$0.42	-1.2%	$0.00	0.0%
		2026	$47.94	$48.33	$48.46	-$0.53	-1.1%	-$0.14	-0.3%
Otter Tail Power Company	48.4%	2021	$33.97	$34.04	$34.53	-$0.56	-1.6%	-$0.49	-1.4%
		2026	$40.87	$41.03	$41.48	-$0.61	-1.5%	-$0.45	-1.1%
Southern Minnesota Municipal Power Agency	100.0%	2021	$31.58	$34.11	$32.86	-$1.28	-3.9%	$1.25	3.8%
		2026	$38.59	$41.75	$39.39	-$0.80	-2.0%	$2.36	6.0%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

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

			Without MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$32.11	$33.46	$33.57	-$1.46	-4.4%	-$0.12	-0.3%
		2026	$39.31	$41.36	$41.16	-$1.84	-4.5%	$0.20	0.5%
Dairyland Power Cooperative	11.5%	2021	$36.24	$38.56	$36.93	-$0.69	-1.9%	$1.64	4.4%
		2026	$45.45	$47.56	$45.15	$0.30	0.7%	$2.41	5.3%
Great River Energy	99.6%	2021	$34.54	$34.71	$35.02	-$0.47	-1.4%	-$0.31	-0.9%
		2026	$43.64	$43.76	$44.00	-$0.37	-0.8%	-$0.24	-0.5%
Minnesota Power and Light Company	100.0%	2021	$34.56	$34.83	$34.95	-$0.38	-1.1%	-$0.11	-0.3%
		2026	$43.23	$43.51	$43.50	-$0.27	-0.6%	$0.01	0.0%
Minnkota Power Coop	45.1%	2021	$36.78	$36.84	$37.23	-$0.45	-1.2%	-$0.39	-1.0%
		2026	$46.09	$46.21	$46.66	-$0.57	-1.2%	-$0.45	-1.0%
Northern States Power Company	74.8%	2021	$35.90	$36.32	$36.33	-$0.44	-1.2%	-$0.02	0.0%
		2026	$48.97	$49.35	$49.22	-$0.25	-0.5%	$0.13	0.3%
Otter Tail Power Company	48.4%	2021	$35.05	$35.04	$35.45	-$0.40	-1.1%	-$0.41	-1.2%
		2026	$42.38	$42.40	$42.87	-$0.49	-1.2%	-$0.47	-1.1%
Southern Minnesota Municipal Power Agency	100.0%	2021	$33.03	$35.53	$34.14	-$1.12	-3.3%	$1.39	4.1%
		2026	$40.82	$43.31	$41.00	-$0.18	-0.5%	$2.31	5.6%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 5
LMP Changes From the 161 kV Rebuild
Minnesota Avg LMP

		With MVP 5			
		Load Weighted Average LMP ($ per MWh)		Average LMP Change	
	Year	Study Case 3: With 161kV Rebuild, Without MVPs 3 & 4	Base Case: Without MVPs 3 & 4	LMP Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$28.27	$28.44	-$0.17	-0.6%
Low Demand	2026	$31.53	$31.85	-$0.32	-1.0%
Business as Usual:	2021	$34.67	$35.02	-$0.35	-1.0%
High Demand	2026	$45.32	$45.64	-$0.32	-0.7%

		Without MVP 5			
		Load Weighted Average LMP ($ per MWh)		Average LMP Change	
	Year	Study Case 6: With 161kV Rebuild Without MVPs 3, 4 & 5	No MVP 5 Base Case: Without MVPs 3, 4 & 5	LMP Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$29.11	$29.21	-$0.10	-0.4%
Low Demand	2026	$32.45	$32.58	-$0.13	-0.4%
Business as Usual:	2021	$35.59	$35.74	-$0.15	-0.4%
High Demand	2026	$46.51	$46.57	-$0.06	-0.1%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.
[2] Minnesota Avg LMP is the load weighted average LMP for Minnesota, calculated as described in Appendix A.

Table 6A
LMP Changes From the 161 kV Rebuild
Business as Usual: Low Demand

			With MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	Percent of Sales in Minnesota	Year	Study Case 3: Without MVPs 3 and 4, 161kV Rebuild	Base Case: Without MVPs 3 and 4	LMP Change Due to 161kV Rebuild	Percent Difference
			[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Alliant West - Interstate Power & Light	5.5%	2021	$29.47	$29.43	$0.04	0.1%
		2026	$33.22	$33.28	-$0.06	-0.2%
Dairyland Power Cooperative	11.5%	2021	$31.02	$31.16	-$0.14	-0.5%
		2026	$34.98	$35.31	-$0.33	-0.9%
Great River Energy	99.6%	2021	$27.79	$28.00	-$0.21	-0.7%
		2026	$30.25	$30.58	-$0.33	-1.1%
Minnesota Power and Light Company	100.0%	2021	$28.52	$28.63	-$0.12	-0.4%
		2026	$31.83	$32.02	-$0.18	-0.6%
Minnkota Power Coop	45.1%	2021	$30.54	$30.65	-$0.11	-0.4%
		2026	$35.01	$35.18	-$0.17	-0.5%
Northern States Power Company	74.8%	2021	$28.22	$28.39	-$0.16	-0.6%
		2026	$31.82	$32.16	-$0.35	-1.1%
Otter Tail Power Company	48.4%	2021	$28.82	$28.95	-$0.13	-0.5%
		2026	$31.48	$31.65	-$0.16	-0.5%
Southern Minnesota Municipal Power Agency	100.0%	2021	$27.17	$27.54	-$0.37	-1.3%
		2026	$28.83	$29.58	-$0.75	-2.5%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 6B
LMP Changes From the 161 kV Rebuild
Business as Usual: Low Demand

			Without MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	Percent of Sales in Minnesota	Year	Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	No MVP 5 Base Case: Without MVPs 3, 4, and 5	LMP Change Due to 161kV Rebuild	Percent Difference
			[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Alliant West - Interstate	5.5%	2021	$30.41	$30.17	$0.24	0.8%
Power & Light		2026	$34.39	$34.00	$0.39	1.2%
Dairyland Power Cooperative	11.5%	2021	$31.74	$31.62	$0.12	0.4%
		2026	$35.69	$35.58	$0.11	0.3%
Great River Energy	99.6%	2021	$28.69	$28.85	-$0.16	-0.6%
		2026	$31.27	$31.44	-$0.17	-0.6%
Minnesota Power and Light	100.0%	2021	$29.21	$29.31	-$0.10	-0.3%
Company		2026	$32.66	$32.72	-$0.05	-0.2%
Minnkota Power Coop	45.1%	2021	$31.13	$31.27	-$0.14	-0.4%
		2026	$35.93	$36.07	-$0.14	-0.4%
Northern States Power	74.8%	2021	$29.00	$29.10	-$0.10	-0.4%
Company		2026	$32.60	$32.76	-$0.16	-0.5%
Otter Tail Power Company	48.4%	2021	$29.79	$29.88	-$0.09	-0.3%
		2026	$32.52	$32.62	-$0.09	-0.3%
Southern Minnesota	100.0%	2021	$28.99	$28.98	$0.01	0.0%
Municipal Power Agency		2026	$31.20	$31.31	-$0.11	-0.3%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 7A
LMP Changes From the 161 kV Rebuild
Business as Usual: High Demand

			With MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	Percent of Sales in Minnesota	Year	Study Case 3: Without MVPs 3 and 4, 161kV Rebuild	Base Case: Without MVPs 3 and 4	LMP Change Due to 161kV Rebuild	Percent Difference
			[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Alliant West - Interstate	5.5%	2021	$33.26	$33.24	$0.03	0.1%
Power & Light		2026	$40.58	$40.45	$0.13	0.3%
Dairyland Power Cooperative	11.5%	2021	$36.00	$36.39	-$0.40	-1.1%
		2026	$43.75	$44.18	-$0.43	-1.0%
Great River Energy	99.6%	2021	$33.83	$34.21	-$0.38	-1.1%
		2026	$42.66	$42.99	-$0.32	-0.7%
Minnesota Power and Light	100.0%	2021	$34.02	$34.28	-$0.26	-0.8%
Company		2026	$42.27	$42.37	-$0.10	-0.2%
Minnkota Power Coop	45.1%	2021	$36.39	$36.57	-$0.18	-0.5%
		2026	$45.38	$45.43	-$0.04	-0.1%
Northern States Power	74.8%	2021	$35.30	$35.66	-$0.35	-1.0%
Company		2026	$48.07	$48.46	-$0.39	-0.8%
Otter Tail Power Company	48.4%	2021	$34.25	$34.53	-$0.28	-0.8%
		2026	$41.42	$41.48	-$0.07	-0.2%
Southern Minnesota	100.0%	2021	$32.11	$32.86	-$0.75	-2.3%
Municipal Power Agency		2026	$38.57	$39.39	-$0.81	-2.1%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 7B
LMP Changes From the 161 kV Rebuild
Business as Usual: High Demand

			Without MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	**Percent of Sales in Minnesota**	**Year**	**Study Case 6: Without MVPs 3 and 4, 161kV Rebuild**	**No MVP 5 Base Case: Without MVPs 3, 4, and 5**	**LMP Change Due to 161kV Rebuild**	**Percent Difference**
			[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Alliant West - Interstate	5.5%	2021	$33.88	$33.57	$0.30	0.9%
Power & Light		2026	$41.54	$41.16	$0.38	0.9%
Dairyland Power Cooperative	11.5%	2021	$36.98	$36.93	$0.05	0.1%
		2026	$44.83	$45.15	-$0.32	-0.7%
Great River Energy	99.6%	2021	$34.82	$35.02	-$0.20	-0.6%
		2026	$43.79	$44.00	-$0.21	-0.5%
Minnesota Power and Light	100.0%	2021	$34.84	$34.95	-$0.11	-0.3%
Company		2026	$43.35	$43.50	-$0.15	-0.3%
Minnkota Power Coop	45.1%	2021	$37.06	$37.23	-$0.16	-0.4%
		2026	$46.44	$46.66	-$0.22	-0.5%
Northern States Power	74.8%	2021	$36.17	$36.33	-$0.16	-0.5%
Company		2026	$49.27	$49.22	$0.05	0.1%
Otter Tail Power Company	48.4%	2021	$35.34	$35.45	-$0.11	-0.3%
		2026	$42.64	$42.87	-$0.23	-0.5%
Southern Minnesota	100.0%	2021	$33.97	$34.14	-$0.17	-0.5%
Municipal Power Agency		2026	$40.80	$41.00	-$0.20	-0.5%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 8
MISO Production Cost Changes From MVPs 3 and 4

With MVP 5

	Year	MISO Production Cost ($ Millions)			MISO Production Cost Change			
		Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$13,217	$13,289	$13,332	-$114.9	-0.9%	-$42.9	-0.3%
Low Demand	2026	$15,474	$15,576	$15,611	-$136.9	-0.9%	-$35.2	-0.2%
Business as Usual:	2021	$15,821	$15,903	$15,953	-$132.2	-0.8%	-$49.5	-0.3%
High Demand	2026	$20,308	$20,451	$20,494	-$185.6	-0.9%	-$43.5	-0.2%

Without MVP 5

	Year	MISO Production Cost ($ Millions)			MISO Production Cost Change			
		Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$13,461	$13,491	$13,556	-$95.3	-0.7%	-$65.4	-0.5%
Low Demand	2026	$15,704	$15,782	$15,843	-$138.7	-0.9%	-$60.4	-0.4%
Business as Usual:	2021	$16,081	$16,121	$16,204	-$122.3	-0.8%	-$82.4	-0.5%
High Demand	2026	$20,587	$20,694	$20,769	-$181.8	-0.9%	-$75.4	-0.4%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 9
MISO Production Cost per MWh Load Changes From MVPs 3 and 4

		With MVP 5						
		MISO Production Cost per MWh Load ($/MWh)			MISO Production Cost per MWh Change			
	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$22.82	$22.95	$23.02	-$0.20	-0.9%	-$0.07	-0.3%
Low Demand	2026	$25.65	$25.82	$25.88	-$0.23	-0.9%	-$0.06	-0.2%
Business as Usual:	2021	$25.67	$25.80	$25.88	-$0.21	-0.8%	-$0.08	-0.3%
High Demand	2026	$30.66	$30.87	$30.94	-$0.28	-0.9%	-$0.07	-0.2%

		Without MVP 5						
		MISO Production Cost per MWh Load ($/MWh)			MISO Production Cost per MWh Change			
	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$23.24	$23.29	$23.41	-$0.16	-0.7%	-$0.11	-0.5%
Low Demand	2026	$26.03	$26.16	$26.26	-$0.23	-0.9%	-$0.10	-0.4%
Business as Usual:	2021	$26.09	$26.15	$26.29	-$0.20	-0.8%	-$0.13	-0.5%
High Demand	2026	$31.08	$31.24	$31.36	-$0.27	-0.9%	-$0.11	-0.4%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 10
MISO Production Cost Changes From the 161 kV Rebuild

		With MVP 5			
		MISO Production Cost ($ Millions)		MISO Production Cost Change	
	Year	Study Case 3: Without MVPs 3 and 4, 161kV Rebuild	Base Case: Without MVPs 3 and 4	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,315	$13,332	-$17.4	-0.1%
Low Demand	2026	$15,595	$15,611	-$16.3	-0.1%
Business as Usual:	2021	$15,933	$15,953	-$19.3	-0.1%
High Demand	2026	$20,470	$20,494	-$23.7	-0.1%

		Without MVP 5			
		MISO Production Cost ($ Millions)		MISO Production Cost Change	
	Year	Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	No MVP 5 Base Case: Without MVPs 3, 4, and 5	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,557	$13,556	$1.4	0.0%
Low Demand	2026	$15,852	$15,843	$9.6	0.1%
Business as Usual:	2021	$16,196	$16,204	-$7.5	0.0%
High Demand	2026	$20,779	$20,769	$10.2	0.0%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 11
MISO Production Cost per MWh Load Changes From the 161 kV Rebuild

		With MVP 5			
		MISO Production Cost per MWh Load ($/MWh)		MISO Production Cost per MWh Change	
	Year	Study Case 3: Without MVPs 3 and 4, 161kV Rebuild	Base Case: Without MVPs 3 and 4	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$22.99	$23.02	-$0.03	-0.1%
Low Demand	2026	$25.85	$25.88	-$0.03	-0.1%
Business as Usual:	2021	$25.85	$25.88	-$0.03	-0.1%
High Demand	2026	$30.90	$30.94	-$0.04	-0.1%

		Without MVP 5			
		MISO Production Cost per MWh Load ($/MWh)		MISO Production Cost per MWh Change	
	Year	Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	No MVP 5 Base Case: Without MVPs 3, 4, and 5	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$23.41	$23.41	$0.00	0.0%
Low Demand	2026	$26.28	$26.26	$0.02	0.1%
Business as Usual:	2021	$26.27	$26.29	-$0.01	0.0%
High Demand	2026	$31.37	$31.36	$0.02	0.0%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Appendix A

PROMOD Modeling and Data

This appendix provides a summary of the PROMOD IV (PROMOD) model, data and assumptions used in analyzing MVPs 3 and 4 and the 161 kV Rebuild, and the methodology for estimating the effect of MVPs 3 and 4 and the 161 kV Rebuild 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.[16] 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."[17] 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,[18]

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

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

[18] 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,[19]
3. unit specifications for existing generation resources,[20]
4. new generation resources based on units planned and under construction,[21]
5. future generation resource additions developed by a capacity expansion model,[22]
6. retirement of generation facilities based on currently announced retirements, but not in response to economic or regulatory factors, including EPA regulation,[23]
7. "hurdle rates" for transactions between NERC regions,[24] and
8. fuel and emission price forecasts.

The system modeled includes individual generator data and much of the transmission information for the Eastern Interconnection,[25] at the bus[26] level.

[19] 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.

[20] 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.

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

[22] 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.

[23] 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.

[24] 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.

[25] 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.

[26] 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.[27] Based on these requirements, MISO's analysis assumes that, with its full 17 MVP project portfolio[28] in service, 8,765 MW of new wind resources will be added in 2021, and an additional 2,272 MW of new wind resources will be added by 2026.[29]

MVPs 3, 4 and 5 represent three projects within the MVP portfolio.[30] These projects are listed in Table A1, and are shown geographically in Figure A1. The 161 kV Rebuild is a project identified in the "Multi-Value Project Planning Study" included in ITC's Certificate of Need Filing for Minnesota—Iowa 345 kV Transmission Project.[31] This Alternative would rebuild the existing Fox Lake – Rutland – Winnebago Jct. 161 kV transmission line to increase the transfer capability.

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
5	N. LaCrosse – N. Madison – Cardinal & Dubuque Co. – Spring Green – Cardinal	345	2018/2020

Source: MISO MVP Report.

[27] 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.

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

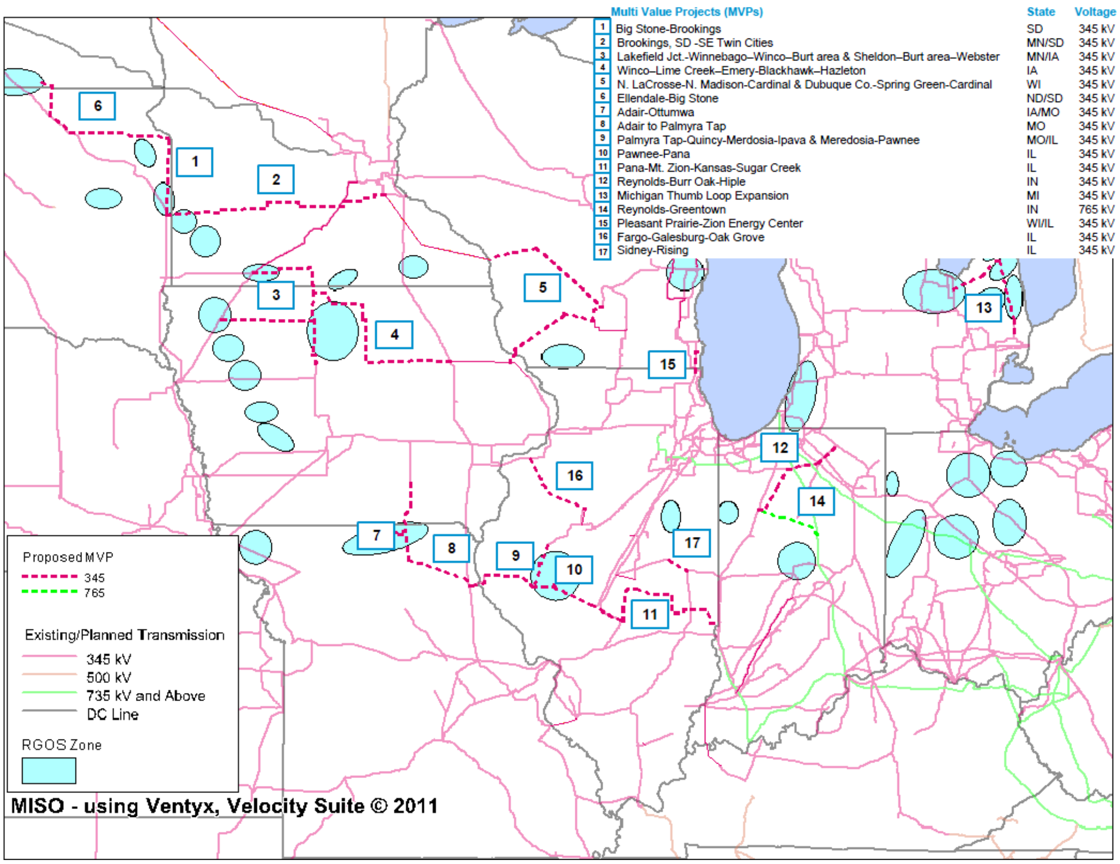
[29] Table 4.2, MVP Report. MISO also finds that the MVP portfolio can support an additional 2,230 MW of wind power from the wind zones without incurring additional reliability constraints. MVP Report, pp. 48-49.

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

[31] Jeff Eddy and Joseph Berry, "ITC Midwest LLC, Multi-Value Project #3 Planning Study," Appendix J, Application of ITC Midwest for a Certificate of Need for the Minnesota-Iowa 345 k V Transmission Project, March 22, 2013.

Figure A1

Map of MVP Portfolio



Source: MISO MVP Report.

The analyses herein estimate the impact of three alternative project configurations – MVPs 3 and 4, MVP 3 without MVP 4, and the 161 kV Rebuild without either MVP 3 or MVP 4 – against two different baseline transmission systems – with and without MVP 5. Impacts are estimated through comparisons of the Study Cases and Base Cases identified in Table A1.

Consider comparisons that assume MVP 5 is in service, which use the Base Case with all 17 of MVP projects except MVPs 3 and 4 (Base Case 1). The first comparison is between a study case that includes all 17 MVP projects in MISO's portfolio (Study Case 1) and a base case (Base Case) that includes only 15 of these MVP projects (all except MVPs 3 and 4). 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 (Study Case 2) and the same Base Case 1 (i.e., a base case that includes all 17 of these MVP projects except MVPs 3 and 4). This comparison provides an indication of the impacts of developing MVP 3 in the absence of MVP 4. The third comparison is between the case that includes the 161 kV Rebuild along with 15 MVP projects in MISO's portfolio (again, all except MVPs 3 and 4), referred to as Study Case 2 and the same Base Case.

Estimates of project impacts without MVP 5 are performed in an analogous fashion, except the Base Case has14 of the MVP projects (all except MVPs 3, 4 and 5). For example, in this case, the first comparison is between a study case that includes all projects in the MVP portfolio other than MVP 5 (referred to as Study Case 4) and a base case that includes only 14 of these MVP projects (all except MVPs 3, 4 and 5). This comparison provides an indication of the impacts of developing both MVPs 3 and 4 when MVP 5 is not in service. The impacts of MVP 3 alone and the 161 kV Rebuild are estimated in the same manner as above, but with MVP 5 not in service in both the Study and Base Cases.

Table A2

Base Cases and Study Cases Considered

With MVP 5 In Service **Base Case** • MVP 3 & 4 Not In Service (Base Case 1) **Study Cases** • MVP 3 & 4 In Service (Study Case 1) • MVP 3 In Service, MVP 4 Not in Service (Study Case 2) • 161 kV Rebuild, MVP 3 and 4 Not In Service (Study Case 3)
With MVP 5 Not In Service **Base Case** • MVP 3, 4 & 5 Not In Service (Base Case 2) **Study Cases** • MVP 3 & 4 In Service, MVP 5 Not In Service (Study Case 4) • MVP3 In Service, MVP 4 & 5 Not in Service (Study Case 5) • 161 kV Rebuild, MVP 3, 4 & 5 Not In Service (Study Case 6)

Note: All other MVP's are assumed to be in service in all base cases and study cases.

All six study cases include each of the 14 MVPs other than MVPs 3, 4 and 5. Apart from differences in which other projects (MVPs 3, 4 and 5 and the 161 kV Rebuild) 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 cases that do not include all 17 MVPs, 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 cases in which some MVPs are not in service, 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 April 2013 Analysis. The quantity of wind curtailments compared to the case in which all 17 MVPs are in service is provided in Table A3.

Table A3

Wind Curtailment, by Case

Description	Wind Curtailment (MW)
With MVP 5 In Service	
MVP 3 and 4 In Service (Study Case 1)	0
MVP3 In Service, MVP 4 Not in Service (Study Case 2)	689
161 kV Rebuild, MVP 4 Not In Service (Study Case 3)	872
MVP 3 & 4 Not In Service (Base Case)	1,130
With MVP 5 Not In Service	
MVP 3 & 4 In Service, MVP 5 Not In Service (Study Case 4)	2,779
MVP 3 In Service, MVP 4 & 5 Not in Service (Study Case 5)	2,958
161 kV Rebuild, MVP 4 & 5 Not In Service (Study Case 6)	3,562
MVP 3, 4 & 5 Not In Service (No MVP 5 Base Case)	3,644

3. ANALYTICAL METHOD

The analysis herein provides estimates of changes in (load-weighted average) wholesale 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 energy prices and annual payments is based on two outputs from the PROMOD model: area LMPs and area loads. 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.[32] Area load is based on the PROMOD inputs

[32] Hours in which the LMP for a Minnesota area is less than -$10/MWh are dropped across all base and study cases for that study year/demand scenario for purposes of calculating an annual load-weighted average LMP. Hours in

developed by MISO, and reflects hour-by-hour load forecasts for individual areas within MISO.[33] 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 (referred to as the "Minnesota Avg 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 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 3 of the main body of this report, are developed using data from the Energy Information Administration.[34] 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 relevant Study Case and Base Case.

The analysis also estimates changes in production costs across the entire MISO region. We refer to these as MISO Production Costs. 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 production costs in its planning studies, such as the MVP Report. 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.

which the LMP for a Minnesota area is greater than $1,000/MWh are capped at $1,000/MWh. As a result of these two corrections, there may be slight LMP differences for some cases/scenarios from the figures reported in the April 2013 LMP Analysis.

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

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

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.[35]

- **Business As Usual: Low Demand** – assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.[36]
- **Business As Usual: High Demand** – assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.[37]

Table A2

Scenario Assumptions[38]

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

[35] MVP Report, p 52.

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

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

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

Table 3-1
LMP Changes From MVPs 3 and 4
Minnesota Avg LMP

WITH MVP 5		Minnesota Avg LMP ($ per MWh)		Minnesota Avg LMP Change	
	Year	With MVPs 3 & 4 (Study Case I)	Without MVPs 3 & 4 (Base Case)	LMP Change Due to MVPs 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$27.96	$28.44	-$0.48	-1.7%
Low Demand	2026	$31.17	$31.85	-$0.68	-2.1%
Business as Usual:	2021	$34.50	$35.02	-$0.52	-1.5%
High Demand	2026	$45.09	$45.64	-$0.55	-1.2%

WITHOUT MVP 5		Minnesota Avg LMP ($ per MWh)		Minnesota Avg LMP Change	
	Year	With MVPs 3 & 4 (Study Case I, no MVP 5)	Without MVPs 3 & 4 (Base Case, no MVP 5)	LMP Change Due to MVPs 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$28.85	$29.21	-$0.36	-1.2%
Low Demand	2026	$32.10	$32.58	-$0.48	-1.5%
Business as Usual:	2021	$35.26	$35.74	-$0.48	-1.3%
High Demand	2026	$46.26	$46.57	-$0.31	-0.7%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Minnesota Avg LMP is the load weighted average LMP for Minnesota, calculated as described in Appendix A of Report III.

Table 3-2
LMP Changes From MVP 3 Only
Minnesota Avg LMP

WITH MVP 5	Year	Minnesota Avg LMP ($ per MWh): With MVP 3 Only (Study Case II)	Minnesota Avg LMP ($ per MWh): Without MVPs 3 & 4 (Base Case)	Minnesota Avg LMP Change: LMP Change Due to MVP 3	Minnesota Avg LMP Change: Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$28.38	$28.44	-$0.06	-0.2%
	2026	$31.84	$31.85	-$0.01	0.0%
Business as Usual: High Demand	2021	$34.96	$35.02	-$0.06	-0.2%
	2026	$45.62	$45.64	-$0.02	-0.1%

WITHOUT MVP 5	Year	Minnesota Avg LMP ($ per MWh): With MVP 3 Only (Study Case II, no MVP 5)	Minnesota Avg LMP ($ per MWh): Without MVPs 3 & 4 (Base Case, no MVP 5)	Minnesota Avg LMP Change: LMP Change Due to MVP 3	Minnesota Avg LMP Change: Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$29.18	$29.21	-$0.02	-0.1%
	2026	$32.63	$32.58	$0.06	0.2%
Business as Usual: High Demand	2021	$35.70	$35.74	-$0.04	-0.1%
	2026	$46.69	$46.57	$0.11	0.2%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Minnesota Avg LMP is the load weighted average LMP for Minnesota, calculated as described in Appendix A of Report III.

Table 3-3
Annual Production Cost Changes From MVPs 3 and 4
MISO Production Costs

WITH MVP 5		MISO Production Cost (Annual, $ Millions)		MISO Production Cost Change	
	Year	With MVPs 3 & 4 (Study Case I)	Without MVPs 3 & 4 (Base Case)	Cost Change Due to MVPs 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,217	$13,332	-$114.9	-0.9%
Low Demand	2026	$15,474	$15,611	-$136.9	-0.9%
Business as Usual:	2021	$15,821	$15,953	-$132.2	-0.8%
High Demand	2026	$20,308	$20,494	-$185.6	-0.9%

WITHOUT MVP 5		MISO Production Cost (Annual, $ Millions)		MISO Production Cost Change	
	Year	With MVPs 3 & 4 (Study Case I, no MVP 5)	Without MVPs 3 & 4 (Base Case, no MVP 5)	Cost Change Due to MVPs 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,461	$13,556	-$95.3	-0.7%
Low Demand	2026	$15,704	$15,843	-$138.7	-0.9%
Business as Usual:	2021	$16,081	$16,204	-$122.3	-0.8%
High Demand	2026	$20,587	$20,769	-$181.8	-0.9%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.

Table 3-4
Annual Production Cost Changes From MVP 3 Only
MISO Production Costs

WITH MVP 5		MISO Production Cost (Annual, $ Millions)		MISO Production Cost Change	
	Year	With MVP 3 Only (Study Case II)	Without MVPs 3 & 4 (Base Case)	Cost Change Due to MVP 3	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,289	$13,332	-$42.9	-0.3%
Low Demand	2026	$15,576	$15,611	-$35.2	-0.2%
Business as Usual:	2021	$15,903	$15,953	-$49.5	-0.3%
High Demand	2026	$20,451	$20,494	-$43.5	-0.2%

WITHOUT MVP 5		MISO Production Cost (Annual, $ Millions)		MISO Production Cost Change	
	Year	With MVP 3 Only (Study Case II, no MVP 5)	Without MVPs 3 & 4 (Base Case, no MVP 5)	Cost Change Due to MVP 3	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,491	$13,556	-$65.4	-0.5%
Low Demand	2026	$15,782	$15,843	-$60.4	-0.4%
Business as Usual:	2021	$16,121	$16,204	-$82.4	-0.5%
High Demand	2026	$20,694	$20,769	-$75.4	-0.4%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.

Table 3-5
Minnesota Emissions Cost Changes From MVPs 3 and 4
MISO CO_2, Minnesota NO_X and Mercury Emissions Costs, Not Adjusted for Emissions from Imports

WITH MVP 5		MISO Minnesota Emissions Cost (Annual, $ Millions)		MISO-Minnesota Emissions Cost Change	
	Year	With MVPs 3 & 4 (Study Case I)	Without MVPs 3 & 4 (Base Case)	Change Due to MVPs 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$9,070	$9,124	-$54.7	-0.6%
	2026	$10,163	$10,218	-$54.7	-0.5%
Business as Usual: High Demand	2021	$9,827	$9,878	-$50.5	-0.5%
	2026	$11,347	$11,400	-$52.9	-0.5%

WITHOUT MVP 5		MISO Minnesota Emissions Cost (Annual, $ Millions)		MISO-Minnesota Emissions Cost Change	
	Year	With MVPs 3 & 4 (Study Case I, no MVP 5)	Without MVPs 3 & 4 (Base Case, no MVP 5)	Change Due to MVPs 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$9,171	$9,223	-$51.6	-0.6%
	2026	$10,260	$10,318	-$58.2	-0.6%
Business as Usual: High Demand	2021	$9,925	$9,976	-$50.9	-0.5%
	2026	$11,441	$11,496	-$55.8	-0.5%

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Assumed environmental externality values are $24.78 per ton of CO_2 in 2021 and $27.11 in 2026, $329.65 per ton of NO_X in 2021 and $360.57 in 2026, and approximately $104.1 million per ton of mercury in 2021 and $113.9 million in 2026.

Table 3-6
Minnesota Emissions Cost Changes From MVP 3 Only
MISO CO_2, Minnesota NO_X and Mercury Emissions Costs, Not Adjusted for Emissions from Imports

WITH MVP 5		MISO Minnesota Emissions Cost (Annual, $ Millions)		MISO-Minnesota Emissions Cost Change	
	Year	With MVP 3 Only (Study Case II)	Without MVPs 3 & 4 (Base Case)	Change Due to MVP 3 Only	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$9,119	$9,124	-$5.8	-0.1%
Low Demand	2026	$10,222	$10,218	$4.1	0.0%
Business as Usual:	2021	$9,880	$9,878	$2.4	0.0%
High Demand	2026	$11,411	$11,400	$11.7	0.1%

WITHOUT MVP 5		MISO Minnesota Emissions Cost (Annual, $ Millions)		MISO-Minnesota Emissions Cost Change	
	Year	With MVP 3 Only (Study Case II, no MVP 5)	Without MVPs 3 & 4 (Base Case, no MVP 5)	Change Due to MVP 3 Only	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$9,211	$9,223	-$12.1	-0.1%
Low Demand	2026	$10,316	$10,318	-$2.5	0.0%
Business as Usual:	2021	$9,968	$9,976	-$7.3	-0.1%
High Demand	2026	$11,503	$11,496	$7.0	0.1%

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Assumed environmental externality values are $24.78 per ton of CO_2 in 2021 and $27.11 in 2026, $329.65 per ton of NO_X in 2021 and $360.57 in 2026, and approximately $104.1 million per ton of mercury in 2021 and $113.9 million in 2026.

Table 1A
Difference in Minnesota Social Cost Change, MVP 3 and 4 Minus 161 kV Rebuild
(Annual, $ Millions)

Expected Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$23.0	-$15.1	-$4.6	-$2.5
Business as Usual: High Demand	-$24.5	-$22.7	-$6.0	$9.1

-30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$29.0	-$21.2	-$10.6	-$8.5
Business as Usual: High Demand	-$30.6	-$28.8	-$12.0	$3.1

+30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$17.0	-$9.1	$1.5	$3.5
Business as Usual: High Demand	-$18.5	-$16.7	$0.0	$15.2

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] In each of these cases, a negative value means that MVP 3 and 4 combined has greater net benefits.

[3] Minnesota Social Costs equals the sum of:
a. The annual revenue requirement for transmission construction costs;
b. The change in Minnesota Production Cost; and
c. The change in Minnesota Emissions Cost.

Table 1B
Difference in Minnesota Social Cost Change, MVP 3 Only Minus 161 kV Rebuild
(Annual, $ Millions)

Expected Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$19.6	-$11.6	-$4.1	$1.5
Business as Usual: High Demand	-$19.5	-$15.4	-$3.4	-$2.1

-30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$22.7	-$14.7	-$7.1	-$1.6
Business as Usual: High Demand	-$22.6	-$18.5	-$6.5	-$5.2

+30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$16.5	-$8.6	-$1.0	$4.6
Business as Usual: High Demand	-$16.4	-$12.4	-$0.3	$0.9

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] In each of these cases, a negative value means that MVP 3 Only has greater net benefits.
[3] Minnesota Social Costs equals the sum of:
a. The annual revenue requirement for transmission construction costs;
b. The change in Minnesota Production Cost; and
c. The change in Minnesota Emissions Cost.

Table 2A

Difference in MISO Social Cost Change, MVP 3 and 4 Minus 161 kV Rebuild

(Annual, $ Millions)

Expected Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$137.8	-$164.6	-$140.0	-$206.5
Business as Usual: High Demand	-$153.5	-$208.0	-$157.6	-$253.2

-30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$143.8	-$170.6	-$146.1	-$212.5
Business as Usual: High Demand	-$159.6	-$214.1	-$163.6	-$259.2

+30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$131.7	-$158.6	-$134.0	-$200.5
Business as Usual: High Demand	-$147.5	-$202.0	-$151.5	-$247.2

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] In each of these cases, a negative value means that MVP 3 and 4 combined has greater net benefits.

[3] MISO Social Costs equals the sum of:

a. The annual revenue requirement for transmission construction costs;
b. The change in MISO Production Cost; and
c. The change in MISO Emissions Cost.

Table 2B
Difference in MISO Social Cost Change, MVP 3 Only Minus 161 kV Rebuild
(Annual, $ Millions)

Expected Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$28.3	-$13.8	-$92.9	-$92.7
Business as Usual: High Demand	-$27.7	-$8.4	-$96.1	-$99.6

-30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$31.4	-$16.9	-$96.0	-$95.8
Business as Usual: High Demand	-$30.8	-$11.5	-$99.2	-$102.7

+30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$25.2	-$10.7	-$89.8	-$89.6
Business as Usual: High Demand	-$24.7	-$5.3	-$93.0	-$96.5

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] In each of these cases, a negative value means that MVP 3 Only has greater net benefits.
[3] MISO Social Costs equals the sum of:
  a. The annual revenue requirement for transmission construction costs;
  b. The change in MISO Production Cost; and
  c. The change in MISO Emissions Cost.

Table 3A
Minnesota Production Cost Changes From MVP 3 and 4

WITH MVP 5		**Minnesota Production Cost (Annual, $ Millions)**		**Minnesota Prod. Cost Change**	
	Year	**With MVP 3 and 4 (Study Case I)**	**Without MVP 3 and 4 (Base Case)**	**Change Due to MVP 3 and 4**	**Percent Difference**
		[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Business as Usual:	2021	$1,332	$1,355	-$22.6	-1.7%
Low Demand	2026	$1,543	$1,562	-$19.3	-1.2%
Business as Usual:	2021	$1,656	$1,683	-$26.9	-1.6%
High Demand	2026	$2,199	$2,226	-$27.5	-1.2%

WITHOUT MVP 5		**Minnesota Production Cost (Annual, $ Millions)**		**Minnesota Prod. Cost Change**	
	Year	**With MVP 3 and 4 (Study Case I, no MVP 5)**	**Without MVP 3 and 4 (Base Case, no MVP 5)**	**Change Due to MVP 3 and 4**	**Percent Difference**
		[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Business as Usual:	2021	$1,419	$1,425	-$6.6	-0.5%
Low Demand	2026	$1,625	$1,632	-$7.3	-0.4%
Business as Usual:	2021	$1,758	$1,767	-$8.5	-0.5%
High Demand	2026	$2,335	$2,326	$8.4	0.4%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.

Table 3B
Minnesota Production Cost Changes From MVP 3 Only

WITH MVP 5		**Minnesota Production Cost (Annual, $ Millions)**		**Minnesota Prod. Cost Change**	
	Year	**With MVP 3 Only (Study Case II)**	**Without MVP 3 and 4 (Base Case)**	**Change Due to MVP 3 Only**	**Percent Difference**
		[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Business as Usual: Low Demand	2021	$1,336	$1,355	-$18.3	-1.3%
	2026	$1,548	$1,562	-$14.1	-0.9%
Business as Usual: High Demand	2021	$1,663	$1,683	-$20.4	-1.2%
	2026	$2,208	$2,226	-$17.7	-0.8%

WITHOUT MVP 5		**Minnesota Production Cost (Annual, $ Millions)**		**Minnesota Prod. Cost Change**	
	Year	**With MVP 3 Only (Study Case II, no MVP 5)**	**Without MVP 3 and 4 (Base Case, no MVP 5)**	**Change Due to MVP 3 Only**	**Percent Difference**
		[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Business as Usual: Low Demand	2021	$1,421	$1,425	-$4.4	-0.3%
	2026	$1,632	$1,632	$.1	0.0%
Business as Usual: High Demand	2021	$1,763	$1,767	-$4.1	-0.2%
	2026	$2,328	$2,326	$1.6	0.1%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.

Table 3C
Minnesota Production Cost Changes From 161 kV Rebuild

WITH MVP 5	Year	Minnesota Production Cost (Annual, $ Millions)		Minnesota Prod. Cost Change	
		With 161 kV Rebuild Only (161 kV Study Case)	Without MVP 3 and 4 (Base Case)	Change Due to 161 kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$1,359	$1,355	$4.5	0.3%
	2026	$1,565	$1,562	$3.0	0.2%
Business as Usual: High Demand	2021	$1,687	$1,683	$4.2	0.2%
	2026	$2,230	$2,226	$3.8	0.2%

WITHOUT MVP 5	Year	Minnesota Production Cost (Annual, $ Millions)		Minnesota Prod. Cost Change	
		With 161 kV Rebuild Only (161 kV Study Case, no MVP 5)	Without MVP 3 and 4 (Base Case, no MVP 5)	Change Due to 161 kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$1,434	$1,425	$8.4	0.6%
	2026	$1,639	$1,632	$7.2	0.4%
Business as Usual: High Demand	2021	$1,776	$1,767	$8.9	0.5%
	2026	$2,340	$2,326	$13.8	0.6%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.

Table 4A

Difference in Minnesota Social Cost Change (Excluding Minnesota Emissions Costs), MVP 3 and 4 Minus 161 kV Rebuild

(Annual, $ Millions)

Expected Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$6.9	-$2.1	$5.1	$5.6
Business as Usual: High Demand	-$10.9	-$11.2	$2.7	$14.8

-30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$13.0	-$8.2	-$0.9	-$0.4
Business as Usual: High Demand	-$16.9	-$17.2	-$3.3	$8.7

+30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	**2026**	**2021**	**2026**
Business as Usual: Low Demand	-$0.9	$3.9	$11.1	$11.7
Business as Usual: High Demand	-$4.8	-$5.2	$8.8	$20.8

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] In each of these cases, a negative value means that MVP 3 and 4 combined has greater net benefits.
[3] Minnesota Social Costs (Excluding Emissions Costs) equals the sum of:
a. The annual revenue requirement for transmission construction costs and
b. The change in Minnesota Production Cost.

Table 4B

Difference in Minnesota Social Cost Change (Excluding Minnesota Emissions Costs), MVP 3 Only Minus 161 kV Rebuild

(Annual, $ Millions)

Expected Cost Scenario

	With MVP 5		Without MVP 5	
	2021	2026	2021	2026
Business as Usual: Low Demand	-$12.5	-$6.8	-$2.5	$3.1
Business as Usual: High Demand	-$14.2	-$11.3	-$2.8	-$1.9

-30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	2026	2021	2026
Business as Usual: Low Demand	-$15.6	-$9.9	-$5.6	$0.1
Business as Usual: High Demand	-$17.3	-$14.3	-$5.9	-$4.9

+30% Cost Scenario

	With MVP 5		Without MVP 5	
	2021	2026	2021	2026
Business as Usual: Low Demand	-$9.4	-$3.7	$0.6	$6.2
Business as Usual: High Demand	-$11.2	-$8.2	$0.3	$1.2

Notes:

[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] In each of these cases, a negative value means that MVP 3 Only has greater net benefits.
[3] Minnesota Social Costs (Excluding Emissions Costs) equals the sum of:
  a. The annual revenue requirement for transmission construction costs and
  b. The change in Minnesota Production Cost.

Table 5A
Minnesota Emissions Cost Changes From MVP 3 and 4
Minnesota CO_2, NO_X, and Mercury Emissions Costs, Adjusted for Emissions from Imports

WITH MVP 5		Minnesota Emissions Cost (Annual, $ Millions)		Minnesota Emissions Cost Change	
	Year	With MVP 3 and 4 (Study Case I)	Without MVP 3 and 4 (Base Case)	Change Due to MVP 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$784	$801	-$17.1	-2.1%
	2026	$854	$869	-$15.0	-1.7%
Business as Usual: High Demand	2021	$874	$888	-$14.6	-1.6%
	2026	$1,007	$1,020	-$12.6	-1.2%

WITHOUT MVP 5		Minnesota Emissions Cost (Annual, $ Millions)		Minnesota Emissions Cost Change	
	Year	With MVP 3 and 4 (Study Case I, no MVP 5)	Without MVP 3 and 4 (Base Case, no MVP 5)	Change Due to MVP 3 and 4	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$839	$845	-$6.6	-0.8%
	2026	$909	$914	-$5.2	-0.6%
Business as Usual: High Demand	2021	$930	$936	-$6.4	-0.7%
	2026	$1,063	$1,065	-$2.5	-0.2%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Assumed environmental externality values are $24.78 per ton of CO_2 in 2021 and $27.11 in 2026, $329.65 per ton of NO_X in 2021 and $360.57 in 2026, and approximately $104.1 million per ton of mercury in 2021 and $113.9 million in 2026.

Table 5B
Minnesota Emissions Cost Changes From MVP 3 Only
Minnesota CO_2, NO_X, and Mercury Emissions Costs, Adjusted for Emissions from Imports

WITH MVP 5	Year	Minnesota Emissions Cost (Annual, $ Millions): With MVP 3 Only (Study Case II)	Minnesota Emissions Cost (Annual, $ Millions): Without MVP 3 and 4 (Base Case)	Minnesota Emissions Cost Change: Change Due to MVP 3 Only	Minnesota Emissions Cost Change: Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$793	$801	-$8.1	-1.0%
	2026	$862	$869	-$6.9	-0.8%
Business as Usual: High Demand	2021	$882	$888	-$6.3	-0.7%
	2026	$1,015	$1,020	-$5.2	-0.5%

WITHOUT MVP 5	Year	Minnesota Emissions Cost (Annual, $ Millions): With MVP 3 Only (Study Case II, no MVP 5)	Minnesota Emissions Cost (Annual, $ Millions): Without MVP 3 and 4 (Base Case, no MVP 5)	Minnesota Emissions Cost Change: Change Due to MVP 3 Only	Minnesota Emissions Cost Change: Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$847	$845	$1.5	0.2%
	2026	$915	$914	$1.3	0.1%
Business as Usual: High Demand	2021	$938	$936	$1.7	0.2%
	2026	$1,068	$1,065	$2.9	0.3%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Assumed environmental externality values are $24.78 per ton of CO_2 in 2021 and $27.11 in 2026, $329.65 per ton of NO_X in 2021 and $360.57 in 2026, and approximately $104.1 million per ton of mercury in 2021 and $113.9 million in 2026.

Table 5C
Minnesota Emissions Cost Changes From 161 kV Rebuild
Minnesota CO_2, NO_X, and Mercury Emissions Costs, Adjusted for Emissions from Imports

WITH MVP 5		Minnesota Emissions Cost (Annual, $ Millions)		Minnesota Emissions Cost Change	
	Year	With 161 kV Rebuild Only (161 kV Study Case)	Without MVP 3 and 4 (Base Case)	Change Due to 161 kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$800	$801	-$1.0	-0.1%
	2026	$867	$869	-$2.0	-0.2%
Business as Usual: High Demand	2021	$887	$888	-$1.0	-0.1%
	2026	$1,019	$1,020	-$1.1	-0.1%

WITHOUT MVP 5		Minnesota Emissions Cost (Annual, $ Millions)		Minnesota Emissions Cost Change	
	Year	With 161 kV Rebuild Only (161 kV Study Case, no MVP 5)	Without MVP 3 and 4 (Base Case, no MVP 5)	Change Due to 161 kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual: Low Demand	2021	$849	$845	$3.1	0.4%
	2026	$917	$914	$2.9	0.3%
Business as Usual: High Demand	2021	$938	$936	$2.3	0.2%
	2026	$1,069	$1,065	$3.1	0.3%

Notes:
[1] MVPs 1-2 and 5-17 are assumed to be in-service in all cases, except in the MVP 5 sensitivity cases.
[2] Assumed environmental externality values are $24.78 per ton of CO_2 in 2021 and $27.11 in 2026, $329.65 per ton of NO_X in 2021 and $360.57 in 2026, and approximately $104.1 million per ton of mercury in 2021 and $113.9 million in 2026.