Legalectric, Inc.

Carol Overland **Attorney at Law, MN #254617**

Energy Consultant—Transmission, Power Plants, Nuclear Waste

overland@legalectric.org

1110 West Avenue
Red Wing, Minnesota 55066
612.227.8638

P.O. Box 69
Port Penn, Delaware 19731
302.834.3466

January 30, 2015

Michael Newmark
Administrative Law Judge
Public Service Commission of Wisconsin
610 North Whitney Way, P.O. Box 7854
Madison, WI 53707-7854

RE: No CapX 2020 Motion for Extension and Motion for Leave to Submit Non-Party Brief
Wisconsin PSC Docket 05-CE-142

Dear Judge Newmark:

Attached please find No CapX 2020 Motion for Extension of Time and Motion for Leave to Submit a Non-Party Brief.

An extension of time for filing of a Non-Party Brief is requested because technical hearing transcripts were not available until Tuesday afternoon of this week, and official transcripts were not ERFed until yesterday.

Thank you for your consideration.

Very truly yours,

Carol A. Overland
Attorney at Law

cc: ERFed and Service List via email

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company LLC and Northern States Power Company – Wisconsin,for Authority to Construct and Place in Service a 345kV Electric Transmission Line from the La Crosse area, in La Crosse County, to the greater Madison area in Dane County, Wisconsin

Docket No. 05-CE-142

NO CAPX 2020
MOTION FOR EXTENSION OF TIME
MOTION FOR LEAVE TO SUBMIT NON-PARTY BRIEF

I. MOTION FOR EXTENSION OF TIME FOR FILING OF NON-PARTY BRIEF

No CapX 2020 makes this Motion for an Extension of Time and requests leave to file a Non-Party Brief on Monday, February 2, 2015. Non-parties do not have access to Technical Hearing transcripts until they are filed online. On Tuesday afternoon, because the transcripts had not yet been filed, counsel for No CapX made a request of parties for transcripts, and Frank Jablonski forwarded them almost immediately. The official transcripts were not filed until Thursday morning, January 29, 2015. No party will be prejudiced by this extension.

Because of this short time with transcripts available, No CapX 2020 requests an extension to file a Non-Party Brief on or before 8:00 a.m. on Monday, February 2, 2015.

II. NO CAPX 2020 REQUESTS ACCEPTANCE OF NON-PARTY BRIEF

No CapX 2020 makes this request to file a Non-Party Brief based on its extensive experience in directly related transmission proceedings and its counsel's experience in transmission proceedings over the last nearly 20 years. Important issues in this case of first impression demand heightened attention, and No CapX submits this Non-Party Brief in an effort to address these issues. No party will be prejudiced by this Motion as this Non-Party Brief will utilize only information in the record of this proceeding.

No CapX 2020 has been an active Intervenor in the CapX 2020 transmission Certificate of Need docket in Minnesota (PUC Docket 06-1115), the CapX 2020 Brookings – Hampton routing docket (PUC Docket 08-1474) Fargo – St. Cloud routing docket (PUC Docket 09-1056, in collaboration with NoRCA), the CapX 2020 Hampton – La Crosse routing docket (PUC Docket 09-1448), the CapX 2020 Hampton – La Crosse CPCN proceeding in Wisconsin (PSC Docket 05-CE-136), and the ITC Midwest MN/IA 345 kV Certificate of Need proceeding.

No CapX 2020's counsel has worked on four dockets directly related to the Badger – Coulee transmission project, specifically the CapX 2020 Certificate of Need docket in Minnesota; the CapX 2020 Hampton – La Crosse transmission routing docket in Minnesota; the CapX 2020 Hampton – La Crosse transmission routing docket in Wisconsin; and the ITC Midwest MN/IA 345 kV project. The ITC Midwest transmission project is much like Badger Coulee in that it is one-half of MISO's MVP 3, as the Badger Coulee project as one-half of MISO's MVP 5. No CapX 2020's brief in that docket is attached to this Motion for reference.

The MISO MVP projects are connected electrically, connected in modeling, connected in claimed benefits, and connected in cost apportionment. These issues have not been sufficiently raised in this Badger Coulee docket. See No CapX 2020 Initial Brief in Minnesota ITC Midwest MN/IA 345 kV. No CapX 2020 requests leave to file a Non-Party brief based on the record in the Badger Coulee docket.

III. WHAT ISSUES HAVE NOT BEEN ADEQUATELY ADDRESSED?

Unfortunately, many issues and much important information has not been drawn out into the record to challenge need claims for this project. For example, the economics and market-based premise of this project and jurisdictional implications the MISO MVP projects and this Badger Coulee portion of MVP 5 project on Wisconsin ratepayers have not been adequately addressed. Applicants make the economic focus of Badger – Coulee clear from the first sentence in their need claim: **The primary reason for constructing the Project is economic…** Badger Coulee Application, Section 2, p. 24.

Where in the Wisconsin statutory criteria is there a basis for approval of a project that is an economic based project? What is the relation to MISO designation as an MVP project, the admitted economic driver for the project, the claimed benefits for this project directly received by Wisconsin ratepayers and the claimed benefits generally, the FERC Ordered 12.38% return on investment, the estimated cost of this solitary "project" and MVP 5 and MVP 17 and the share apportioned of each to Wisconsin ratepayers, and the Wisconsin statutory criteria for a CPCN? Where is the challenge to the fundamental assumptions of this project?

Because this is a proceeding before the Wisconsin Public Service Commission, it is benefits distinct to Wisconsin at issue, and those benefits to Wisconsin from this project are not credibly distinct. What portion of those claimed "benefits" would be realized in Wisconsin, and what benefits would be realized in Wisconsin due to this project alone, in combination with MVP 3, 4 and the other half of MVP 5? To what extent are benefits reliant on construction of all 17 projects, all of which were included in PROMOD modeling assumptions? What "benefits" of the MVP Portfolio are specifically attributable to half of MVP 5 as a stand alone project?

Because this is a proceeding before the Wisconsin Public Service Commission, the PSC must also consider the cost of this MVP project. Likewise, it is the costs to Wisconsin at issue, and as with benefits, the costs to Wisconsin of this project are not credibly distinct. Analysis of costs of this project goes beyond the reasonableness of the project's increasing cost estimate, and should also address the cost of the MISO MVP projects, estimated at $5.191 **BILLION**. A portion of that $5.191 billion will be apportioned to Wisconsin ratepayers, a portion for this project, a portion for all of MVP 5, and a portion for the entire MISO MVP Portfolio. As with the economic costs of this project, what are the environmental costs of this project as a necessary part of MVP 5 and a necessary part of the 17 project MISO MVP Portfolio?

These are examples of some of the basic questions that have not been adequately addressed in the proceeding thus far. No party actively challenged the need for this project, at best offering up alternatives. An economic-based segmented project that is one-half of one of the MISO 17 project MVP Portfolio does not meet criteria for a Certificate of Convenience and Necessity for this project under Wisconsin law.

IV. NO CAPX 2020 REQUESTS LEAVE TO SUBMIT NON-PARTY BRIEF FOR CONSIDERATION IN THIS DOCKET ON MONDAY, FEBRUARY 2, 2015

No CapX 2020 makes this Motion for Leave to File a Non-Party Brief based on its participation in multiple transmission dockets, counsel's experience in these and other transmission dockets, and because of knowledge of MISO MVP issues not brought out by parties in this Badger – Coulee docket. No CapX 2020 requests leave to file the Non-Party Brief on or before 8:00 a.m. Monday, February 2, 2015 due to the inability of Non-Parties to access the transcripts of the Technical Hearings to Non-Parties. No party will be prejudiced by a short extension.

Dated: January 30, 2015

Carol A. Overland

Carol A. Overland MN Lic. 254617
Attorney at Law
1110 West Avenue
Red Wing, MN 55066
(612) 227-8638
overland@legalectric.org

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE 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	OAH Docket No.: 60-2500-30782 PUC Docket No.: ET-6675/TL-12-1337 ET-6675/CN-12-1053

NOTICE OF WITHDRAWAL OF COUNSEL
for
CITIZENS ENERGY TASK FORCE

PLEASE TAKE NOTICE THAT THE UNDERSIGNED attorney, Carol A. Overland has hereby withdrawn as counsel for Citizens Energy Task Force in the above-entitled action.

Carol A. Overland continues as counsel for No CapX 2020.

September 2, 2014

Carol A Overland

Carol A. Overland #254617
Attorney at Law
1110 West Avenue
Red Wing, MN 55066
(612) 227-8638
overland@legalectric.org

STATE OF MINNESOTA
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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	OAH Docket No.: 60-2500-30782 PUC Docket No.: ET-6675/TL-12-1337 ET-6675/CN-12-1053

CITIZENS ENERGY TASK FORCE AND NO CAPX 2020

INITIAL BRIEF

Citizens Energy Task Force and NoCapX 2020, intervenors in the above-captioned docket, submit this Initial Brief and request that the Applications for a Certificate of Need and Route Permit be denied. The task before the Commission is to make a decision based upon established policy and the public and ratepayer interests.

I. INTRODUCTION

This is a case of first impression in Minnesota, where a transmission-only company Applicant has requested a Certificate of Need and Routing Permit for a segmented portion of a multi-project "portfolio" project extending across the region. No CapX 2020 and CETF agree with the Applicants that the Commission should consider all of the costs and benefits of the MISO 17 project MVP Portfolio as a part of this proceeding, since MVP Project 3 was studied by MISO as part of the larger portfolio of projects. The MVP 17 project portfolio is MISO's promotional business plan to enable marketing of low-cost electricity from the Dakotas in the northwest to Madison/Milwaukee, Illinois, and beyond. A marketing plan is not need, and desire to gain financially by increasing marketing range is not need, lowering production costs is not need, nor is wanting a return of 12.38% on the capital costs of transmission construction need. Applicants claim a need for this project, capital costs of transmission construction need. Applicants claim a need for this project, but a legally recognized "need" has not been defined or demonstrated. These ITC Midwest Applications should be denied.

Transmission infrastructure has a decades-long lifespan, and any decision at this point will affect energy choices through the infrastructure's life, and ours. Approval of this one project commits Minnesotans to paying a share of a 17 project portfolio, one that is claiming a vast tally of economic benefits dependent on construction of all 17 projects. The rate recovery scheme for transmission has changed from an historical requirement that generators pay for necessary upgrades to a ratepayer pay scheme set by MISO and approved by FERC. The project cost of the project was estimated at $194-206 million for the ITC MN portion of MVP 3 in the Application, later at $273-285; initially $271-283 million for all of MVP 3; $1,710-1,868 for MVP 3 & 4; $5,214-5,821 for the 17 MVP Portfolio; and $8,789-16,407 when totaling revenue requirements for the 17 MVP projects.

The project cost will be paid by utilities utilizing the wholesale transfer services provided by these projects, estimated to be a 13.3% share for Minnesotans of the MVP 17 project portfolio capital costs of $5,821,866,035, or $774,308,182.65 for Minnesota. In addition to these FERC set capital costs, transmission service costs for services utilized would be an additional ratepayer burden. These rate schemes for capital costs and service costs are FERC rates, over which the Commission has no jurisdiction. Thus, the review of this project for a Certificate of Need and a Route Permit and the Commission's decision has significant policy implications for ratepayers. In its review of this project, the Commission has been asked by Applicants to take into account a range of benefits, from those of MVP 3 and 4 to claimed benefits achieved only with the full 17 MVP Portfolio, and these Intervenors agree. In consideration of the range of benefits, the Commission must also take into account the full range of costs and impacts associated with not "just" MVP projects 3 and 4, but also the full range of $5,821,866,035 of MVP costs and the associated environmental impact costs.

This ITC MN/IA project is but a small part of a phased and connected action, part of a large portfolio of projects that will admittedly enable transmission of baseload generation to distant markets contravening Minnesota energy policy; where the cost estimate is not reasonably assured to be accurate; where benefits of multiple projects are claimed, but where the costs attributed to the project are only to a very small part. This project does not meet the Minnesota statutory criteria for a Certificate of Need, and it also does not meet the very criteria that MISO has established for MVP projects.

The ITC Midwest, LLC Minnesota/Iowa 345 kV Transmission Project is not needed

under the criteria for a Certificate of Need found in Minn. Stat. §216B.243:

> **Subd. 3.Showing required for construction.**
> No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:
>
> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;
>
> (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;
>
> (3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;
>
> (4) promotional activities that may have given rise to the demand for this facility;

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;

(7) the policies, rules, and regulations of other state and federal agencies and local governments;

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;

(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a; and

(12) (for generation, deleted)

Subd. 3a.Use of renewable resource.
The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

Minn. Stat. §216B.243, Subd. 3, 3a.

The criteria used by MISO to develop the MVP Portfolio of projects is different than Minnesota's criteria for determining need, but this project does not meet MISO's criteria either:

Criterion 1

A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. 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, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.

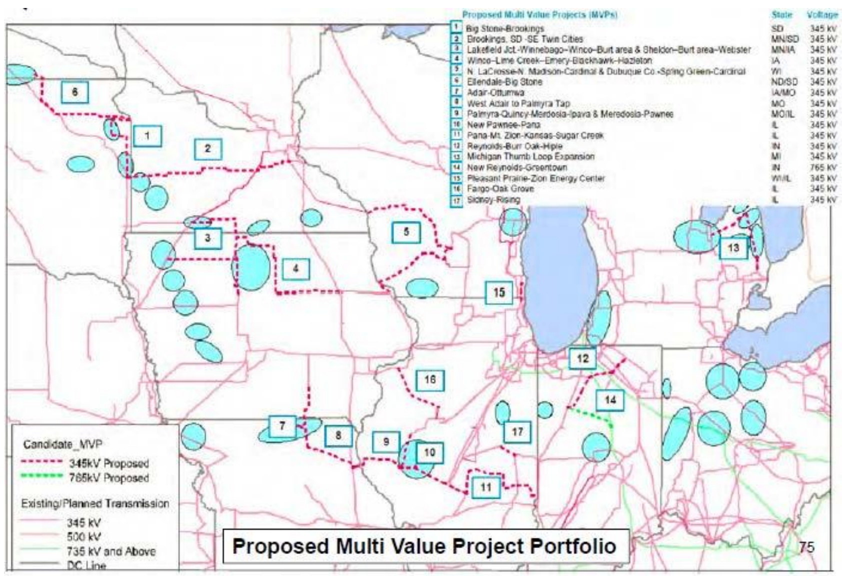
Criterion 3

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 based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

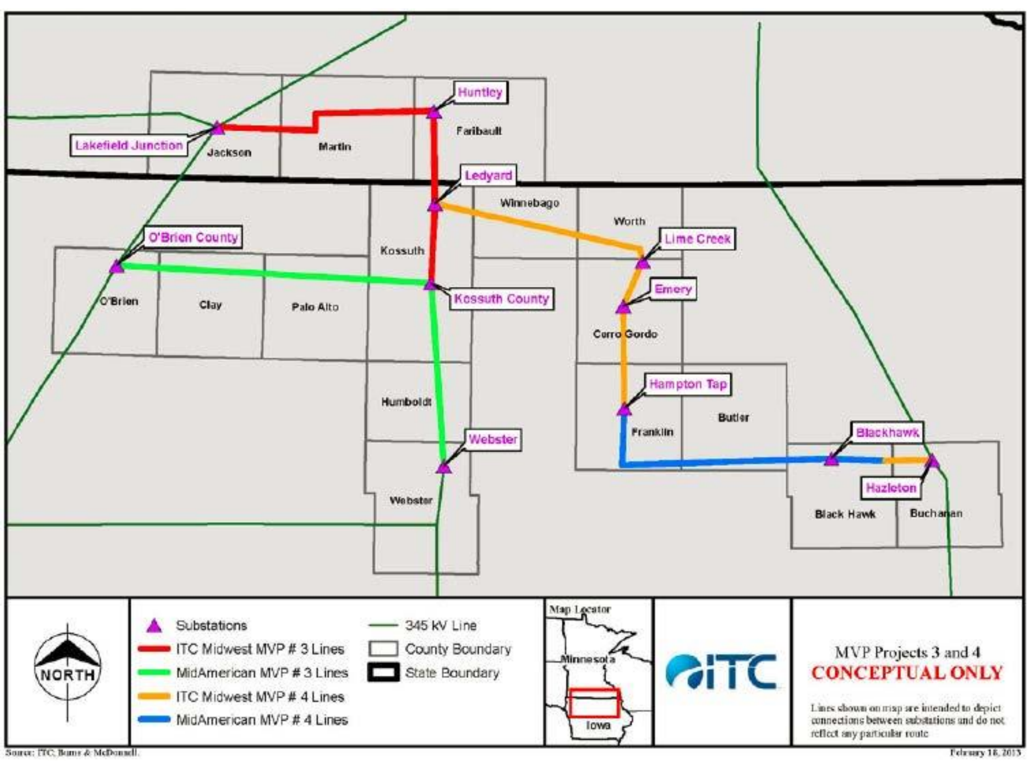
Ex. 6, Application, Appendix I, MTEP 11, p. 49. While these MISO criterion are not determinative in Minnesota, even under the MISO criteria, the project is not justified.

II. FACTUAL BACKGROUND

The ITC Midwest MN/IA Transmission Project is a project of ITC Midwest, a transmission-only company, a 345 kV transmission line extending from the Lakefield Junction substation eastward to a new “Huntley Substation” located just south of the existing Winnebago Junction substation, and then south to the Iowa line, where it will continue in Iowa to a new “Ledyard Substation” and on to a new MidAmerican Energy Company substation in Kossuth County. Ex. 6, Application, p. 1. The project applied for is part of MVP 3, directly connected to MVP 4, and one of seventeen "Multi Value Projects" established by MISO in MTEP 11 that link with the extra high voltage (EHV) system to carry electricity from the Dakotas in the northwest to Illinois and beyond:



Ex. 6, Application, Appendix I, p. 7.



Ex. 6, Application, p. 2, Map of MVP 3 and 4.

The part at issue in this Minnesota proceeding is the part of the red line on the above map from Jackson, Minnesota to the IA border. MVP 3 is divided with roughly one-third in Minnesota and two-thirds in Iowa, and ownership is divided 50/50 between ITC Midwest and Mid American. MVP 3 is shaped like a backwards "F" with parallel lines drawing in from the 345 kV connections to the west like a tuning fork, running easterly, and then a connecting line running north/south.

MVP 4, linked and to be considered with MVP 3, then runs eastward from MVP 3, and connects into the existing 345 kV transmission in Iowa, and which then connects to MVP 5, extending further east. See Ex. 30, corrected Collins Rebuttal, p. 15, l. 17. MVP 5 is in part the Badger Coulee line from La Crosse to Madison, Wisconsin, in which No CapX 2020 and CETF are also intervenors MVP 5 is the part connecting MVP 3 and MVP 4 and existing Iowa transmission to Madison, Milwaukee, Chicago and eastward.

This ITC Midwest Minnesota/Iowa 345 kV transmission line will be a high capacity double circuited line, utilizing structures on a 200 foot Right of Way to be double circuited with either two 345 kV phases or one 345kV and a 161 kV phase, all using two twisted pair 345 kV 26/7 Drake (2-795) aluminum conductor steel reinforced conductor cables with a capacity equivalent of 3,000 amps and 1,800 MVA. Ex. 6, Application, p. 17-18; Fairmont Tr., p. 123, l. 14- 124, l. 7. The substation includes space for "a future bay position to allow for three future connections." Id., p. 25-26. Future plans are not found in the Application or record.

This MN/IA 345 kV project is designed as a for-profit private purpose line needed to "remove Minnesota and regional transmission system constraints which currently limit the ability to reliably deliver generation throughout the MISO footprint," to "enhance the regional electrical system, and "contribute to a portfolio of regional projects with significant reliability, economic, and public policy benefits in Minnesota and the greater region. Ex. 6, Application, p. 7, p. 1; p. 15. 'ITC Midwest is not a retail load serving entity." Id., p. 16. This project is a part of the 17 project MVP Portfolio established by MISO in MTEP 11, with a strategy focused on:

> Regional transmission, such as the transmission in the proposed MVP portfolio, increases reliability in the MISO footprint, opens the market to increased competition and provides **access to low cost generation, regardless of fuel type.**

Ex. 6, Application, Appendix I, MTEP 11, p. 51. This specific MVP project's purpose:

> **Lakefield to Winnebago to Winco-Burt, Lime Creek to Emery to Blackhawk to Hazleton, Sheldon to Burt to Webster 345kV**
>
> These lines facilitate transfer of wind from MISO's West Region closer to large load centers in Illinois and Wisconsin by connecting existing wind heavy areas around Lakefield and Sheldon, and further accessing wind in central Iowa from the Lime Creek area to Hazleton. It provides on and off ramps for power transfer through intermediate transformations.

Ex. 6, Application, App. I, p. 106.

MISO's MTEP 11 establishment of these MVP projects muddies the jurisdictional waters by layering an "approval" by a private entity over state jurisdiction. MISO's purpose in establishing MVP projects is to coordinate with existing infrastructure and supporting a variety of different generation fuel sources to provide economic benefits and to beef up the system to enable delivery across the region. Id., p. 7. The criteria used by MISO to develop the MVP Portfolio of projects is different than Minnesota's criteria for determining need:

> **Criterion 1**
>
> A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the

minimum or maximum amount of energy that can be generated. 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, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.

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 based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

Ex. 6, Application, Appendix I, MTEP 11, p. 49.

The MVP economic benefits are taken as a whole, based upon PROMOD modeling presuming all 17 projects are approved and constructed, include a number of drivers:

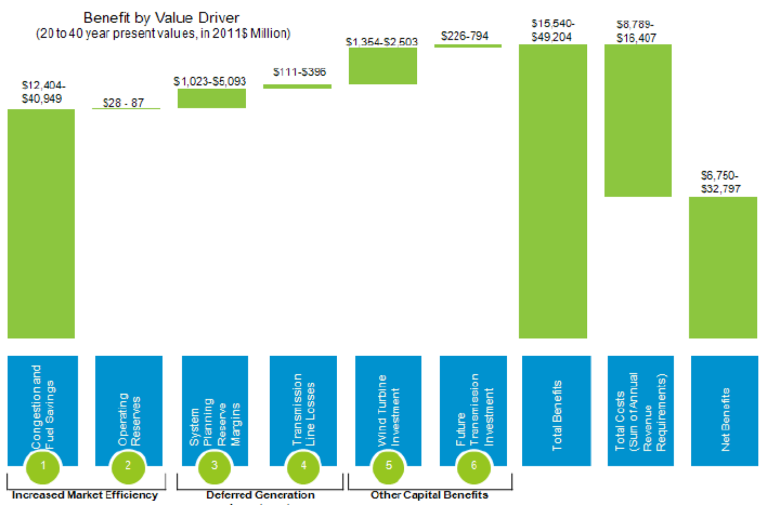


Figure 4.1-13: Proposed MVP portfolio economic benefits

Ex. 6, Application, App. I, MTEP 11, p. 64; see also Ex. 300, Goggins Direct, p. 28-29 (cut and paste of MTEP 11). This chart shows questionable attribution of benefits, such as "Wind Turbine Investment" which would occur wherever wind turbines are built, i.e., nearer load.

It also identifies net costs of $8,789,000,000 - $16,407,000,000, the sum of annual revenue requirements, which is much higher than the capital costs shown in Schedule 26A, identified as $5,821,866,035.00, or MTEP 11 at $5,197,000,000.00.

The economic benefits of the transmission build-out measure in the billions over the life of these projects. Specific claimed areas of "benefits" include:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.

- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.

- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.

- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.

- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

Ex. 6, Application, Appendix I, MTEP 11, p. 49.

> Regional transmission, such as the transmission in the proposed MVP portfolio, increases reliability in the MISO footprint, opens the market to increased competition and provides access to low cost generation, regardless of fuel type.

Ex. 6, Application, Appendix I, MTEP 11, p. 51.

The application also establishes that it is not about Minnesota, or even regional, market, showing that there is no shortage of electricity to go around:

Reserve margin	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reserve margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
Reserve margin (percent)	27.0	24.8	24.2	23.3	22.5	21.5	20.5	21.0	19.9	18.6
Planning reserve margin requirement (percent)	17.4	17.3	17.3	17.2	17.4	17.8	17.8	18	18.2	18.2

Table 1.2: 2012-2021 forecasted reserves

Ex. 6, Application, Appendix I, MTEP 11, p. 9.

The MTEP 11 transmission projects, including the MVP 17 project portfolio and this ITC MN/IA transmission line is not "for wind," first, because under FERC regulations, transmission service may not discriminate among users in any way, including fuel type. The proposed projects in MTEP, if built, increase wind generation by 6.74% but there's only a infinitesimal 0.85% decrease in coal:

		Generation (MWH)	Capacity Factor
Combined Cycle	No Appendix projects.	25,267,913	21.22 percent
	With Appendix projects.	20,804,817	17.47 percent
	Change	-4,463,096	-3.75 percent
CT Gas	No Appendix projects.	3,252,613	1.61 percent
	With Appendix projects.	2,352,304	1.16 percent
	Change	-900,309	-0.45 percent
CT Oil	No Appendix projects.	68,820	0.16 percent
	With Appendix projects.	15,908	0.04 percent
	Change	-52,913	-0.12 percent
Hydro	No Appendix projects.	3,744,454	34.25 percent
	With Appendix projects.	3,744,116	34.25 percent
	Change	-338	0.00 percent
IGCC	No Appendix projects.	5,860,686	76.29 percent
	With Appendix projects.	5,854,798	76.21 percent
	Change	-5,888	-0.08 percent
Nuclear	No Appendix projects.	71,312,762	88.91 percent
	With Appendix projects.	71,312,762	88.91 percent
	Change	0	0.00 percent
ST Coal	No Appendix projects.	383,096,341	68.34 percent
	With Appendix projects.	378,307,444	67.49 percent
	Change	-4,788,897	-0.85 percent
ST Gas	No Appendix projects.	708,331	2.86 percent
	With Appendix projects.	453,482	1.83 percent
	Change	-254,849	-1.03 percent
ST Oil	No Appendix projects.	12,209	0.24 percent
	With Appendix projects.	12,399	0.24 percent
	Change	189	0.00 percent
Wind	No Appendix Projects	42,108,491	27.99 percent
	With Appendix Projects	52,251,508	34.73 percent
	Change	10,143,018	6.74 percent

Table 2.5-6: 2016 generation and capacity factor change for different type units

This project and the entire 17 project MISO MVP Portfolio, at -0.85% decrease, will have a negligible impact on decrease. The failure of the MVP Portfolio to decrease coal generation is supported by MISO's witness Chatterjee, who clarified that the purpose of the MVP projects is baseload unit transfer capacity:

> *You're trying to move capacity resources or, capital P, capital R, planning resources. These are baseload units that you're moving from local resource zone one for utilization in all of the other MISO local resource zones for every load to meet their local -- to meet their planning reserve margin requirement.*
>
> *So you know how much you need and you know what you're transferring, you're transferring capacity resources, baseload units, and wind also, but wind has a very small capacity credit value. And we identified a significant benefit there. So that is an important context.*

MISO's Chatterjee, Tr. p. 94-95.

The purpose of this build-out is to add to the existing and under construction transmission web and ship electricity from where there is a surplus to where there is a market with higher prices. See Ex. 6, Application, App. I, MTEP 11.

The Applicants claim that "MVP Project 3 and MVP Project 4 will result in lower cost energy for Minnesota consumers, and that:

> … construction of these two MVP projects will cause the average Minnesota LMP to drop by $0.61 and $0.70 per megawatt hour ("MWh") in 2021, depending on studied market conditions. In 2026, the reductions are $0.71 and $0.090 per MWh depending on market conditions. For Minnesota, these LMP reductions result in a reduction in annual LMP payments of between $48.3 million to $76.6 million across the cases evaluated.

Ex. 6, Application, p. 8; Appendix M.

However, in this case, consideration of costs has many layers. MVP 3 is just one of the 17 projects in the MISO MVP Portfolio. Applicants testify that benefits of MVP 3 and 4 must be considered in this case, and that the project portion of MVP 3 and MVP 3 cannot be considered in a vacuum. Ex. 30, corrected Collins Rebuttal, p. 15, l. 17; Ex. 29, Berry Rebuttal, pps. 5 & 31. All 17 projects were part of the MVP modeling, and for the claimed benefits of the Multi Value Portfolio projects to be realized, all 17 of the projects must be built. Ex. 6, Application, Appendix I, MTEP 11, p. 1, 42-75. Applicants acknowledge the interwoven nature of these 17 projects and testify that:

> The Commission should consider all of the costs and benefits of the MISO 17 project MVP Portfolio as a part of this proceeding, since MVP Project 3 was studied by MISO as part of the larger portfolio of projects.

Ex. 31, Grover Rebuttal, p. 3, l. 8-11; see also Ex. 203, Johnson, p. 7;

The MTEP 11 estimates the seventeen MVP projects to cost a total, in 2011 dollars, of $5.197 billion:

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[28]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co.–Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo–Galesburg-Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 4.1-1: Proposed MVP portfolio

Ex. 6, Application, Appendix I, MTEP 11 Table 4.1-1. Since this chart was published, Schedule 26A shows that costs have increased on all but MVP 4, from Winco to Hazelton, which has dropped to roughly $464 million:

Figure 1. Approved MVPs

Project ID [1]	Project Name [2]	Geographic Location by TO Member System [3]	Estimated In-Service Date of Complete Project [4]	Estimated Project Cost (in Nominal Dollars) [5]
1203	Brookings, SD - SE Twin Cities 345 kV	XEL/GRE/OTP/MRES/CMMPA (represents TO ownership)	12/26/2014	$639,873,000
2202	Reynolds to Greentown 765 kV line	Pioneer, NIPS	6/1/2018	$328,708,150
2220	Ellendale to Big Stone South	OTP, MDU	12/31/2019	$395,670,000
2221	Big Stone South to Brookings	OTP, NSP	9/30/2017	$226,720,000
2237	Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	AMIL	11/15/2019	$354,737,600
2239	Sidney to Rising 345 kV line	AMIL	11/15/2016	$66,322,958
2248	Adair - Ottumwa 345	AMMO, ITCM, MEC	11/15/2018	$178,230,921
2844	Pleasant Prairie-Zion Energy Center 345 kV line	ATC	12/31/2013	$34,175,000
3017	Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	AMIL	11/15/2017	$505,692,729
3022	Fargo-Galesburg-Oak Grove 345 kV Line	AMIL, MEC	11/15/2018	$225,524,474
3127	N LaCrosse-N Madison-Cardinal -Spring Green - Dubuque area 345-kV	ATC, NSP, ITCM	12/31/2018	$863,032,583
3168	Michigan Thumb Wind Zone	ITC	12/31/2015	$510,000,000
3169	Pawnee to Pana - 345 kV Line	AMIL	11/15/2018	$108,600,381
3170	Adair-Palmyra Tap 345 kV Line	AMMO	11/15/2018	$108,110,058
3203	Reynolds to Burr Oak to Hiple 345 kV	NIPS	12/31/2019	$271,000,000
3205	Lakefield Jct. - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster 345 kV line	MEC, ITCM	6/1/2018	$541,119,569
3213	Winco to Hazelton 345 kV line	MEC, ITCM	12/31/2018	$464,348,611
			Total	$5,821,866,035

Applicants state the costs of "ITC Midwest Estimated Cost for the Minnesota Portion of the MN-IA Project" is $194-206 million, that part of MVP 3 from Lakefield Junction to the Minnesota border. Ex. 6, Application, p. 29. There is no substation at the Minnesota – Iowa border. Applicants state the costs from the border to the Kossuth County substation is an additional $77 million, plus/minus 30%. Id. Commerce witness Johnson requested the entire MVP 3 cost be considered, increased to $273-285 million for the project, and ITC has refused to agree to a cap of $283 million. Ex. 30, Collins Rebuttal p. 16-17; Ex. 204, Johnson Surrebuttal, p. 5.

MVP 3 in 2011 dollars is estimated to cost $511 million, up from $506 million in MTEP 11. Revised, see also Ex. 6, Application, Appendix I, MTEP 11 Table 4.1-1.

Project Description	Cost
MN/IA Lakefield Jct. to Iowa border	194-206
IA border to Kossuth substation	77
ITC part of MVP 3 – Lakefield Jct. to Kossuth	271 - 283
MVP 3	511 - 541

MVP 3 and 4	996 - 1,005
MVP 3, 4 and 5 (from App. I & Schedule 26A)	1,710 - 1,868
MVP Portfolio – all 17 required for "benefits"	5,214 - 5,821
Total of revenue requirements - MTEP	8,789 – 16,407

ITC Midwest will reap a 12.38% rate of return, set in a MISO tariff and approved by FERC:

> *MR. DAVE GROVER: Yeah. ITC is a transmission company and our rates are regulated by the Federal Energy Regulatory Commission. That's in contrast to local vertically integrated utilities, like Interstate Power & Light or Xcel Energy, who also are, you know, publicly-owned, investor-owned utilities that have their rates regulated. And typical utility rate regulation models, utilities earn a return on their rate base and they are granted a rate of return on the equity portion of investment in the rate base.*
>
> *So I know this is complicated stuff that probably people don't think about, but, I mean, we have a return on equity in our FERC rate of* ***12.38 percent****, I believe is the number.*
>
> *MR. MAYNARD JAGODZINSKE: Pardon? One more time?*
>
> *MR. DAVE GROVER: On the equity portion of investment in rate base, we have a FERC-granted rate of return, or a return on equity, rather, of* ***12.38 percent.***

Tr. p. 185-186 (emphasis added); see also MISO Tariff MM and Schedule 26A.

The cost to Minnesota ratepayers is at issue. ITC Midwest claims that:

> Based on an estimated MN-IA Project cost of $283 million and the MISO cost allocation methodologies, the estimated first year Project revenue requirement to be collected from Minnesota energy customers would be approximately $7 million for the ITC Midwest portion of MVP Project 3.

Ex. 6, Application, p. 7; Appendix E. The total of revenue requirements would be much higher. ITC's Grover states that Minnesota customer load will pay approximately 13.3% of all MVP Portfolio project costs. Ex. 31, Grover Rebuttal, p. 3-4. 13.3 percent of all MVP Portfolio project costs, whichever project cost figure is used, is significantly more than $7 million. Using the 2013 Schedule 26A MVP Portfolio total of $5,821,000,000.00, 13.3% of that cost is $774,193,000.00 for Minnesota ratepayers.

Commerce witnesses all pointed out significant problems with the cost estimates and failure to produce one number as the "cost" of the project. Ex. 205, Rakow Direct, p. 19-29; Ex. 203 and 204, Johnson Direct and Surrebuttal and Attachments.

The Commission does not have sufficient information to determine the cost of this project. There are too many cost estimates floating in this docket to pin down. ITC Midwest has not produced a reliable cost estimate, and the inconsistencies have not been clarified. This project should not be considered for a Certificate of Need without a reliable cost estimate.

III. **ITC'S TRANSMISSION PROJECT DOES NOT MEET MINNESOTA'S STATUTORY CRITERIA.**

The ITC Midwest MN/IA Transmission Project is a project designed as a for-profit private purpose line to serve ITC's wholesale transmission service customers. It is a part of one of the 17 projects in the MISO MVP Portfolio. Applicants claim this project is needed to "enhance the regional electrical system, and "contribute to a portfolio of regional projects with significant reliability, economic, and public policy benefits in Minnesota and the greater region. Ex. 6, Application, p. 1; p. 15. Applicants also claim that the project is needed due to "insufficient generation outlet capacity," "congestion on the Fox Lake – Rutland – Winnebago 161 kV line,' and "reduced system reliability due to SPSs for contested Fox Lake – Rutland – Winnebago 161 kV line" (the second two are really one issue). Ex. 6, Application, p. 47-70; see also Id., 71-86. However, a system protection scheme is not justification for new transmission, it is a mechanism by which the system can operate while congested. See Ex. 202, Heinen Direct, p. 7-10. In addition, as above, this is a pass through line planned to enhance market transactions to points outside of Minnesota, moving baseload generation to easterly markets.

In corrected Rebuttal testimony, Applicants make a very important admission – that the project should not be considered in a vacuum, and must be considered in light of the complete MVP 3 and also MVP 4 and the 17 MVP project portfolio:

> southwest Minnesota and northwest Iowa. The segment of MVP Project 3 that ITC Midwest proposes to construct and own, the Project, by itself is needed to address constraints in southwest Minnesota and to provide transfer capability. The collective MVP Project 3 segments provide additional benefits to Minnesota and, in conjunction with MVP Project 4, address additional needs in Iowa. The need for and benefits of the Project must be evaluated in the context of MVP Project 3 and the entire MVP Portfolio.

ITC Midwest has not met its statutory burden – it has not demonstrated need for the project as required by Minnesota statute and rules.

a. **Accuracy of Forecasting**

Typically, the Commission must take "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility," and the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based." See Minn. R. 7849.0270; 7849.0280; 7849.0290 , but c.f. 7849.0120 A(1). Again, Applicant sought to be exempted from the decision point regarding accuracy of forecasts, and the Commission denied the request. Accuracy of peak demand and forecasting and methodology are to be evaluated. In this case, because Applicant has no service territory, but does have a transmission system, the Commission ordered information be provided regarding binding constraints, wind curtailment, and special protection schemes, and that the commission consider "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility." In this case, the forecasts show that there is no demand, that there is sufficient supply:

Reserve margin	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reserve margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
Reserve margin (percent)	27.0	24.8	24.2	23.3	22.5	21.5	20.5	21.0	19.9	18.6
Planning reserve margin requirement (percent)	17.4	17.3	17.3	17.2	17.4	17.8	17.8	18	18.2	18.2

Table 1.2: 2012-2021 forecasted reserves

Ex. 6, Application, Appendix I, MTEP 11, p. 9.

Applicants instead tout claimed "benefits" as justification for a Certificate of Need. A claim of benefits as "need" will be addressed below.

b. Impact of Project on Conservation Efforts

Under both statute and rule, the Commission must take the impact of the project on conservation efforts into account, Minn. Stat. §216B.243, Subd. 3(2); Minn. R. 7849.0120(A)(2). This project and the MVP Portfolio spends over $5 billion to lock into place the infrastructure that circumvents conservation and instead promotes bulk power transfer over long distances, inherently inefficient, and relies on market transactions to address need rather than conservation. In this case, it is binary, because if there is market and it can be dispatched to that market, sale of coal generated electricity will occur.

c. Promotional Activities

Under both statute and rule, the Commission must take "promotional activities that may have given rise to the demand for the facility" into account, Minn. Stat. §216B.243, Subd. 3(1); Minn. R. 7849.0120(A)(3). The statute and rule require the Commission to take a hard look at the promotional activities to assure that an Applicant is not manufacturing its own "need." Unfortunately, that is exactly what has happened here, where the Applicant developed this marketing plan to reap the benefits of regional transmission. That the Applicant has a wholesale marketing plan from which many utilities and transmission companies may reap private benefits is not sufficient justification for a Certificate of Need and burdening Minnesota ratepayers for a share of this $5+ billion transmission package.

At the outset, Applicants requested to be exempted from the application of this rule, but Commerce staff noted that it was a decision point, not a data requirement, and the Commission rejected exemption based on the Commerce argument.

This distinction is particularly important in this proceeding because it is the first MISO Multi Value Project to come before the Commission since MTEP 11, and also because it is the first MVP project to be applied for by a transmission only company.

As to this project as the first MVP project to come before the Commission, policy precedent will be established with the Commission's decision. What is the role of the Commission in need determinations regarding projects that are economic based? These MISO MVP Portfolio are projects fit into the existing and under construction transmission web with the specific purpose of bringing surplus generation in western MISO to easterly markets. The analysis for this portfolio was market based, economic PROMOD modeling, and the basis for applying to build the portfolio projects are the benefits claimed – economic benefits. In essence, this portfolio is a massive coordinated marketing promotional scheme, developed over many years in many venues. See Ex. 6, Application, Appendix G, p. 1, Figure 12. This Portfolio was developed to provide benefits to wholesale generators, transmission service providers, and wholesale customers – the claimed benefits of this project may or may not trickle down to retail customers, and there is no scheme revealed in this Application. The Commission is to address Minnesota and regional benefits, and costs, but much is unknown at the time this first MVP project is under review.

Secondly, this project has been applied for by a transmission only company. By definition, it is a private purpose. The rate of return is incorporated into MISO tariffs and are formally set by the Federal Energy Regulatory Commission (FERC). While the Commission has no jurisdiction over rates, it does have jurisdiction over issuing a Certificate of Need, and with that jurisdiction, an obligation to review costs and benefits to the people of Minnesota. How is a more than $5 billion marketing plan in the public interest?

d. **Congestion is an Economic Issue, not a Reliability Issue**

The congestion claimed in the area proposed for the transmission project, and specifically congestion claimed on the Fox Lake line, is not sufficient justification for transmission. The line is currently operating under a System Protection Scheme, one which has been in existence for over a decade and which is functioning well. See Ex. 202, Heinen Direct, p. 8-10. After a thorough review, Heinen concluded that "it is unclear whether there are still reliability concerns to be addressed in the area." Id., p. 10.

Congestion, on the other hand, is an economic issue, one claimed as a driver for this project. See Ex. 6, Application, App. I, MTEP 11, p. 64. Congestion as an economic issue is not a reliability issue.

e. Economic Benefits are not "Benefits" under the Statute

The ITC Midwest project proposal relies on a claim of benefits provided by the project. Two criteria in the Certificate of Need statute do refer to benefits:

> (5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;
>
> (9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

Minn. Stat. §216B.243, Subd. 3(5),(9).

Applicants tout the economic benefits that the MVP Projects will provide, but this begs an analysis including identifying the benefactors and the extent of the benefits modeled to be provided by the project at issue. This issue was raised by Commerce in Information Requests, specifically, "information on the impacts of the failure to construct MVP 4, MVP 5 and both projects," resulting in a revision of the LMP and Production Costs analysis, which showed that benefits from the ITC Midwest portion of MVP 3, and of MVP 3 are nominal, and dependent on MVP 4 and MVP 5. Ex. 33, Schatzki Rebuttal, Schedule 2.

First, as an insight into the beneficiaries of the claimed benefits, Locational Marginal Price (LMP) is the wholesale electricity price, a price paid by those purchasing electricity on the wholesale market. Production Costs are the costs of electric production for the producers. Id., p. 8. This LMP and Production Cost analysis is performed with PROMOD, which is a market simulation model. Id. PROMOD market simulation will not address environmental quality or increased reliability of energy supply, nor will it address enhanced regional reliability, access, or deliverability. Minn. Stat. §216B.243, Subd. 3(5), (9). More importantly, it will not address Minnesota benefits:

> 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 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. 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.

Ex. 33, Schatzki Rebuttal, Schedule 2, p. 7 of 36.

> The PROMOD modeling assumes in its study case that all 17 MVPs are inservice.
>
> 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".

Id., p. 9. The results are found in this brief, inserted immediately following this brief.

The locational marginal price analysis is found in Tables 2 through 4, with Table 2 being a summary, and Table 3 and 4 the itemized LMPs for the Business as Usual: High Demand and Business as Usual: Low Demand sensitivities. Id., pps. 15-19. The results of this modeling is mixed, particularly when looking at the itemizations. In the summary, in all cases, the LMP change due to MVP 3 only is negligible, and in the BAU without MVP 5, it shows a small cost in the 2026 outyear.

The production cost analysis is found in Tables 8 and 9 Id., p. 25-26. In Table 8, "MISO Production Cost Changes from MVPs 3 and 4" the annual MISO production cost change with MVP 5 is shown for "Cost Change Due to MVP 3 only" as a difference ranging from -0.2% to -0.3%, and "Cost Change Due to MVPs 3 and 4" as ranging from 0.8% to 0.9%. Without MVP 5, "Cost Change Due to MVP 3 only" ranges from -0.4 to -0.5% and "Cost Change Due to MVPs 3 and 4" as ranging from 0.7% to 0.9%. These results are for the entire MISO footprint and are negligible. There is no breakdown of benefit to Minnesota. What small percentage is shown as a benefit is for the entire MISO footprint, and there is no benefit demonstrated for Minnesota.

In Table 9, "MISO Production Cos7 per MWh Load Changes from MVPs 3 and 4" the annual MISO production cost per MWh load change with MVP 5 is shown for "Cost Change Due to MVP 3 only" as a difference ranging from -0.2% to -0.3%, and "Cost Change Due to MVPs 3 and 4" as ranging from 0.8% to 0.9%. Without MVP 5, "Cost Change Due to MVP 3 only" ranges from -0.4 to -0.5% and "Cost Change Due to MVPs 3 and 4" as ranging from 0.7% to 0.9%. Again, these results are for the entire MISO footprint and are negligible. There is no breakdown of benefit to Minnesota. What small percentage is shown as a benefit is for the entire MISO footprint, and there is no benefit demonstrated for Minnesota.

Applicants attempt to build a case for benefits of their project as applicable to Minnesota, but fail to demonstrate a substantive benefit.

II. ITC'S TRANSMISSION LINE IS NOT JUSTIFIED UNDER THE MISO CRITERIA.

MISO developed the MVP Portfolio utilizing its own privately developed MVP Criteria, and under this criteria, the project is not justified.

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 based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

Ex. 6, Application, Appendix I, MTEP 11, p. 49.

The Applicants rely on the constraints present in the Fox Lake line and use of a "System Protection Scheme" to satisfy this criteria, yet the necessity of a System Protection Scheme (SPS) is not a NERC violation, it is a means to assure that the line is operate safely, without putting the system at risk. It is a choice of the Applicants to desire a system without SPS, and not a NERC or FERC requirement.

Commerce reviewed the SPS situation in detail through Information Requests. See Ex. 202, Heinen Direct, p. 8-10.

III. IT'S NOT FOR WIND -- THE PROJECT ENABLES COAL

The MVP criteria is clear that the type of generation is not part of the criteria, in keeping with FERC's directives of non-discrimination. See MVP Criteria, Ex. 6, Application, App. I, MTEP 11. State renewable mandates do not link required increases in renewable generation with a mandate for decreased fossil or nuclear generation. Minn. Stat. § 216B.1691. No state in the MISO region or the nation has a renewable energy mandate/standard that requires decreased fossil fuel or nuclear generation.

The impact of this transmission build-out is that it is adding capacity on top of existing transmission, transmission that carries a high percentage of coal generation. The addition of transmission capacity, rather than shutting down coal plants, means that the coal remains on the wires and through this transmission system, is available for marketing and may be dispatched to nearly any customer. In locations further east where coal plants may be limited by new regulations, North Dakota's coal plants will be running and able to supply that gap in production. According to a study commissioned by MISO regarding the benefits of the transmission build-out confirmed that the economic benefits are best achieved when coal generation displaces natural gas.[1] Building transmission enables coal generation to continue.

The role of this project in compliance with Renewable Energy Standards is overstated. Minnesota's utilities have met RES standards or are well on their way:

Table 1: Minnesota RES Compliance Plans

Utility	Docket	Compliant through	Compliance Plan
Interstate Power	14-77	2014	No specific plan given.[3]
Missouri River	10-735	2021	Red Rock Hydro, 36 MW in 2018.[4]
SMMPA	13-1104	2022	23 MW Wind annually starting 2021.
Minnesota Power	13-53	2022	Does not include Bison 4 wind farm.[5]
Xcel Energy	13-716	2023	See also 13-603.
MMPA	13-1165	2023	Petition pg 28 DOC Comment Apr 21
Minnkota	10-782	2023	
Otter Tail Power	13-961	2024	
Great River Energy	12-1114	2024	Wind: 100 MW in 2024, 300 MW in 2025, and 200 MW in 2026.

Ex. 207, Rakow Rebuttal, Table 1, p. 6. As Dr. Rakow states, "the point is that the Minnesota RES is not driving the need for this line in the near term. Most likely the

[1] See ICF's Independent Assessment of Midwest ISO Operational Benefits:

20145-99338-04	PUBLIC	12-1053	☐	CN	CETF AND NO CAPX2020	COMMENTS--DEIS COMMENTS OF CETF AND NO CAPX - ICF INDEPENDENT ASSESSMENT OF MIDWEST ISO OPERATIONAL BENEFITS	05/09/2014

incremental impact of the proposed line, if built, would be to transmit renewable power along with power from new natural gas generating plants that might be interconnected into the area. Id., l. 4-7.

MISO overstates potential for curtailment of wind generation and claims that 3 million MWh would be curtailed, contrary to historical levels of curtailments at less than one-third that rate. Id., p. 3-4. AWEA's Goggins also overstates wind capacity needed, making the same error as MISO's Chatterjee in underestimating Minnesota utility compliance with RES. Id. p. 8.

Neither MISO's Chatterjee nor AWEA's Goggins address the relative cost of line loss when transmitting energy from a low capacity factor generating source over distance or how much additional wind generation would need to be built to compensate for the inherent line loss. Instead, Goggins parrots the MTEP MVP claim of line loss savings:

> The MVP Report explains the transmission line loss savings as:
>
> > The addition of the recommended MVP portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs. Specifically, when installed generation capacity is just sufficient to meet peak system load plus the planning reserve margin, a reduction in transmission losses reduces the amount of generation that must be built.[41]

Ex. 300, Goggins Direct, p. 28.

MISO's witness Chatterjee, who clarified that the purpose of the MVP projects is baseload unit transfer capacity:

> You're trying to move capacity resources or, capital P, capital R, planning resources. These are baseload units that you're moving from local resource zone one for utilization in all of the other MISO local resource zones for every load to meet their local -- to meet their planning reserve margin requirement.
>
> So you know how much you need and you know what you're transferring, you're transferring capacity resources, baseload units, and wind also, but wind has a very small capacity credit value. And we identified a significant benefit there. So that is an important context.

MISO's Chatterjee, Tr. p. 94-95.

Further, Minnesota's public policy mandates and goals pertaining to renewable energy do not mandate outlets for new renewable generation – there is no state mandate for export! See Ex. 22, Berry Direct, p. 6.

AWEA's Goggins conflates wind with decreased coal generation by claiming, in testifying in support of this project, that water consumption is lowered by wind generation and that lower consumption of water would be a benefit to Minnesota's agricultural industry. Goggins fails to note that there is no mandated link between increasing wind generation and decreased "conventional forms of generation," and that the Minnesota RES does not mandate decreased coal production:

> Wind also plays an important role in offsetting water consumption at other forms of electricity generation. Because wind energy requires virtually zero water, while most conventional forms of electricity generation consume hundreds of gallons of water per MWh produced, the DOE report mentioned above found that achieving 20% wind would save 4 trillion gallons through the year 2030.[63] These water savings would produce broadly spread benefits, as all people consume water. These benefits would be particularly large in an agricultural state like Minnesota, and the benefit of reduced costs for producing food and other agricultural products would benefit all consumers.

Ex. 300, Goggins Direct, p. 38. There is no "offsetting" link.

Some may state that coal will be shut down with the new EPA regulations. Shutdown of coal based on regulations is not assured, based on the recent federal decision that found the Next Generation Energy Act (2007) unconstitutional. In addition to that holding, the decision notes several relevant plans for increases in coal on the wires. First, it notes that the Dry Fork coal plant has been moved from the West into the Eastern Interconnect, making it "new coal" now heading our way, potential for an additional unit at Dry Fork. Also in that decision it discusses plans for a new coal fired plant in South Dakota and surplus at the Milton Young, which the decision states would be exacerbated by transmission prohibitions of the Next Generation Energy Act. This means, conversely, that transmission would alleviate that problem surplus.[2]

An important omission in this record is that no party has testified and no party has entered evidence regarding the amount of wind in the MISO queue in Illinois. Illinois has had significant wind development, Chicago has long been known as the "Windy City," and "Wind on the Wires" exported from Minnesota and Iowa could have a detrimental impact on wind development in Illinois, generation which would be near load, would not require as significant transmission construction, and which would not lose much of its energy through line loss.

V. ALTERNATIVES ANALYSIS IS SKEWED BY ECONOMIC "NEED"

There is no "need" for this project in the statutory sense. Minn. Stat. §216B.243. The "need" is a desire for regional transmission for the economic market, and for the economic benefits that could be realized with such a regional transfer capability. The only

[2] See State of North Dakota v. Beverly Heydinger, et al., Federal Case No. 11-CV-3232, available online: http://www.troutmansandersenergyreport.com/wp-content/uploads/2014/04/April-18-Dist-of-Minn-Order.pdf

alternatives considered were transmission "alternatives," which is logical in that no alternative other than a massive transmission build-out would facilitate the regional marketing business plan, but as an alternatives analysis, it is inadequate and misleading.

The "alternatives" analyzed by MISO were limited:

- A "do-nothing" alternative was first considered. This alternative was used as a baseline to determine the system performance in delivering future generation requirements to load. It was demonstrated that, without major additions to the regional transmission system, significant generation curtailment would be required to maintain system reliability. Such a system would lead to heavy system loading conditions, potential instabilities, reduced reliability margins and would limit the ability of the states in the MISO footprint to meet their renewable energy mandates. As such, it was determined that significant system enhancements would be needed to meet renewable energy mandates and maintain system reliability.

- An alternative build-out based on a piecemeal resolution of each facility experiencing an overload was considered. Such a plan would build incremental local upgrades to mitigate the reliability issues directly caused by the injection of the mandated wind into the transmission system. This would result in a minimum of 650 transmission projects, as compared to the 17 larger projects that comprise the proposed

  Also, this alternative would cost approximately $4.7 billion, based only upon the constraints found in the steady state reliability analysis. Additional investment would most likely be required to mitigate the constraints found in the stability analyses**. This alternative would provide much lower benefits to the MISO system, as it does not provide long term solutions that increase the regional transmission capability.** This solution would enable less wind to be delivered, endangering the ability of the states in the MISO footprint to meet their renewable energy mandates. **It would provide significantly less economic benefits, as the regional values quantified below would be reduced or eliminated.**

Ex. 6, Application, Appendix I, MTEP 11, p. 63 (emphasis added). Note the alternatives considered are transmission only.

The alternatives analysis produced in the Application for this specific project were for Iowa MVPs and again, the alternatives considered were transmission only. Ex. 6, Application, App. J, Proposed MVP Reliability Analysis Alternatives Discussion, TSTF, September 16, 2001.

VI. ENVIRONMENTAL REVIEW IS INADEQUATE

In this docket, the environmental review is inadequate because it was not completed

The Minnesota Environmental Policy Act (MEPA) specifies that the "final detailed environmental impact statement… shall accompany the proposal through an administrative review process."

> *Prior to the preparation of a final environmental impact statement, the governmental unit responsible for the statement shall consult with and request the comments of every governmental office which has jurisdiction by law or special expertise with respect to any environmental effect involved. Copies of the drafts of such statements and the comments and views of the appropriate offices shall be made available to the public.* ***The final detailed environmental impact statement and the comments received thereon shall precede final decisions on the proposed action and shall accompany the proposal through an administrative review process.***

Minn. Stat. §116D.04, Subd. 6a.Comments (emphasis added).

This MEPA mandated accompaniment cannot logically occur when the Environmental Impact Statement is released after the public and evidentiary hearings have been completed and after public comment closes.

This lack of FEIS comment opportunity for the public was problematic in this case. Because the public did not have the opportunity to comment on the FEIS, it was not closely scrutinized. However, a Final EIS may contain information that is not correct, and the public must have the opportunity to review the FEIS and comment on its adequacy.

Extension of the deadline for public comments regarding FEIS adequacy is particularly important in this case, because there are no local residents, landowners, or otherwise interested local parties who have intervened. Parties have the ability to comment on the adequacy of the FEIS in their briefs, but landowners, local residents, and other interested parties do not, and thus they cannot file briefs containing FEIS adequacy comments. Even formal parties will have little time to review the FEIS, and the intervening parties are unfamiliar with the area and would have difficulty commenting. Public participation in review of the adequacy of the FEIS would help inform the record.

The rule chapter governing environmental review generally, Minn. R. Ch. 4410, does not apply to Power Plant Siting Act dockets, and the requisite 10 day comment period for a Final Environmental Impact Statement in that chapter is not directly inapplicable. Minn. R. 4410.2800, Subp. 2; 7850.2500, Subp. 12. However, the Power Plant Siting Act rules do require that the Commission make several determinations regarding the adequacy of the EIS.

> **7859.2500, Subp. 10. Adequacy determination.**
>
> The Public Utilities Commission shall determine the adequacy of the final environmental impact statement. The commission shall not decide the adequacy for at least ten days after the availability of the final environmental impact statement is announced in the EQB Monitor. The final environmental impact statement is adequate if it:
>
> A. addresses the issues and alternatives raised in scoping to a reasonable extent considering the availability of information and the time limitations for considering the permit application;
>
> B. provides responses to the timely substantive comments received during the draft environmental impact statement review process; and
>
> C. was prepared in compliance with the procedures in parts 7850.1000 to 7850.5600.
>
> If the commission finds that the environmental impact statement is not adequate, the commission shall direct the staff to respond to the deficiencies and resubmit the revised environmental impact statement to the commission as soon as possible.

Minn. R. Ch. 7850.2500, Subp. 10.

Extension of the public comment period also furthers the operational principles of The Power Plant Siting Act:

> **216E.08 PUBLIC PARTICIPATION.**
>
> **Subd. 2.Other public participation.**

> The commission shall adopt broad spectrum citizen participation as a principal of operation. The form of public participation shall not be limited to public hearings and advisory task forces and shall be consistent with the commission's rules and guidelines as provided for in section 216E.16.

Based on the premise of the Power Plant Siting Act of encouraging and furthering public participation and the Commission's "principal of operation," CETF and No CapX 2020 again request a short comment period, at least one week, after the filing of the FEIS to address its adequacy. The people are the ones on the ground who are best able to inform the record, they are the ones who would most likely know if important issues are not adequately addressed or are being given short shrift, and they are the ones with the most at stake in a routing proceeding. Public participation can prevent material errors.

IV. CONCLUSION

CETF and No CapX 2020 await a determination regarding the Motion for Extension of the period for Public Comment filed on May 12, 2014., requesting additional time to receive the Final Environmental Impact Statement in the record and for the public to have at least one week to comment on the adequacy of the environmental review. Adequacy of the environmental review is at issue and the Commission must make several determinations regarding environmental review. Minn. R. 7850.2500, Subp. 10.

Citizens Energy Task Force and NoCapX 2020, intervenors in the above-captioned docket, submit this Initial Brief and request that the Applications for a Certificate of Need and Route Permit be denied. This Recommendation should provide support for the Commission to make a decision based upon established policy and the public and ratepayer interests.

In this case of first impression in Minnesota, where a transmission-only company Applicant has requested a Certificate of Need and Routing Permit for a segmented portion of a multi-project "portfolio" project extending across the region, No CapX 2020 and CETF request that these Applications be denied. Review and analysis of the project should consider all of the costs and benefits of the MISO 17 project MVP Portfolio as a part of this proceeding. Because the MVP 17 project portfolio is nothing more than MISO's promotional business plan to enable marketing of low-cost electricity from the Dakotas in the northwest to Madison/Milwaukee, Illinois, and beyond, it is not a justification for a Certificate of Need. A marketing plan, desire to gain financially by increasing marketing range, lowering production costs, or a return of 12.38% on the capital costs of transmission construction do not constitute need under Minnesota's Certificate of Need criteria. These permits must be denied.

Other than that the Routing Permit should be denied, CETF and No CapX 2020 take no position as to the route of the project.

Respectfully submitted,

July 11, 2014

Carol A Overland

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Carol A. Overland #254617
Attorney for CETF and No CapX2020
Legalectric
1110 West Avenue
Red Wing, MN 55066
(612) 227-8638
overland@legalectric.org

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 2
LMP Changes From MVPs 3 and 4
Minnesota Avg LMP

With MVP 5

		Load Weighted Average LMP ($ per MWh)			Average LMP 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	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

		Load Weighted Average LMP ($ per MWh)			Average LMP 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	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	5.5%	2021	$29.08	$29.65	$29.43	-$0.35	-1.2%	$0.22	0.8%
Power & Light		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	100.0%	2021	$28.23	$28.50	$28.63	-$0.40	-1.4%	-$0.13	-0.4%
Company		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	74.8%	2021	$27.92	$28.32	$28.39	-$0.47	-1.7%	-$0.06	-0.2%
Company		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	100.0%	2021	$26.55	$28.67	$27.54	-$0.99	-3.6%	$1.13	4.1%
Municipal Power Agency		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	5.5%	2021	$29.32	$30.29	$30.17	-$0.85	-2.8%	$0.11	0.4%
Power & Light		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	100.0%	2021	$29.01	$29.18	$29.31	-$0.31	-1.1%	-$0.13	-0.5%
Company		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	74.8%	2021	$28.75	$29.08	$29.10	-$0.35	-1.2%	-$0.02	-0.1%
Company		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	100.0%	2021	$28.21	$30.46	$28.98	-$0.77	-2.7%	$1.48	5.1%
Municipal Power Agency		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	5.5%	2021	$32.39	$33.39	$33.24	-$0.84	-2.5%	$0.15	0.5%
Power & Light		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	100.0%	2021	$33.77	$34.13	$34.28	-$0.51	-1.5%	-$0.16	-0.5%
Company		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	74.8%	2021	$35.24	$35.65	$35.66	-$0.42	-1.2%	$0.00	0.0%
Company		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	100.0%	2021	$31.58	$34.11	$32.86	-$1.28	-3.9%	$1.25	3.8%
Municipal Power Agency		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	5.5%	2021	$32.11	$33.46	$33.57	-$1.46	-4.4%	-$0.12	-0.3%
Power & Light		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	100.0%	2021	$34.56	$34.83	$34.95	-$0.38	-1.1%	-$0.11	-0.3%
Company		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	74.8%	2021	$35.90	$36.32	$36.33	-$0.44	-1.2%	-$0.02	0.0%
Company		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	100.0%	2021	$33.03	$35.53	$34.14	-$1.12	-3.3%	$1.39	4.1%
Municipal Power Agency		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.