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September 23, 2014

Burl Haar
Executive Secretary
Public Utilities Commission
121 – 7th Place East, Suite 350
St. Paul, MN 55101

eFiled and eServed

RE: ITC Midwest MN/IA Transmission Project
PUC Docket 12-1053

Dear Dr. Haar:

Enclosed, eFiled, and eServed please find No CapX 2020 Exceptions to Report of Admnistrative Law Judge.

Thank you for your consideration. If you have any questions or require anything further, please let me know.

Very truly yours,

Carol A. Overland
Attorney at Law

BEFORE THE
STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
Dan Lipschultz	**Commissioner**
Betsy Wergin	**Commissioner**

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

NO CAPX 2020 EXCEPTIONS TO THE RECOMMENDATION OF THE ADMINISTRATIVE LAW JUDGE

No CapX 2020, a limited intervenor in this proceeding specifically granted opportunity to submit Exceptions to the Recommendation of the Administrative Law Judge, hereby submits these Exceptions.[1] No CapX 2020 requests that the Certificate of Need be denied because the Applicant has not met its burden of proof and production, and in the alternative, that it be remanded to the Administrative Law Judge to build the record and for more thoughtful analysis. No CapX 2020 also requests oral argument in this docket when it comes before the Commission.

No CapX 2020 was a "limited" intervenor due to its out-of-time request for intervention based on intervention filings of Izaak Walton League, Fresh Energy and Minnesota Center for Environmental Advocacy on the deadline, an indication that a critical review was needed. Subsequently, upon familiarization with the filings, it was apparent that this project, as the first

[1] This writer was originally counsel for both CETF and No CapX 2020, but withdrew from representation of Citizens Energy Task Force in the Badger Coulee docket in Wisconsin on August 28, 2014, and in this ITC Midwest docket on September 2, 2014.

declared MISO MVP Project before the Commission,[2] needed more than cursory oversight. CETF/No CapX 2020 did move for a more active role and acceptance as a full party, such as Discovery, questioning of witnesses, but this request was denied. CETF/No CapX 2020 was allowed to submit documents into the public record as Public Comment, and was allowed very limited questioning of two witnesses at the Evidentiary Hearing.

The record in this matter is materially deficient. DOC DER raised significant material and fatal deficiencies in the record that were ignored in the ALJ's Recommendation. No CapX urges the Commission to take the DOC DER exceptions to heart.

The ALJ's Recommendation was a cut-and-paste of the Applicant's wishes, and misapplied a burden of proof to the DOC DER:

> The DOC DER is justifiably concerned about the cost of the Project. The DOC DER, however, has failed to identify a reasonably prudent alternative.

DOC DER Exceptions, p. 6. ITC Midwest, as the applicant, has the burden of proof and production, and it has not met its burden.

The Dept. of Commerce recommended denial of the Certificate of Need, and at literally the last moment, the Sunday evening prior to the Monday start of the Evidentiary Hearing, Dr. Rakow changed his testimony and Commerce changed its position, ostensibly based on public comments heard at the Public Hearing. Dr. Rakow did not question those commentors and did nothing to confirm their statements nor did he request that they make their statements under oath. Less than twenty-four hours before the hearing, the Commerce position morphed to:

> The Department takes no position regarding which alternative best meets the criteria established by Minnesota States and Minnesota Rules. The data available in the record indicate that the proposed Project would allow a wind farm with a Commission-approved PPA (the Odell Wind Farm) to be interconnected albeit at

[2] The CapX 2020 Brookings – Hampton project was not declared a MISO MVP project until several years after it was granted a Certificate of Need by the Commission – knowledge of which, as an "economic" project, might have affected the outcome of that Certificate of Need application.

> costs that may greatly exceed the cost estimates provided by ITC. ITC and MISO failed to provide transmission data regarding the ability of the 161 Rebuild to interconnect the Odell Wind Farm.

Commerce Proposed Findings of Fact 103.[3] As noted by Commerce, there was no information regarding the ability of the 161 Rebuild to interconnect.

This case was tried on the filings, with virtually no live testimony. CETF/No CapX 2020 was allowed to ask very limited questions at the public hearings of those witnesses present, and at the "Evidentiary Hearing," very limited questions of Dr. Rakow regarding his sudden shift in Testimony and Commerce's change in position. CETF/No CapX 2020 was allowed to ask exactly three (3) questions of MISO's Chatterjee, resulting in a significant admission that it's all about "baseload." No other intervenor had questions for witnesses during the public hearing or evidentiary hearing.

Generally, the Findings of Facts in the Recommendation mirror those Findings proposed by the Applicant, a cut and paste with only minor format changes, and do not take into account the substantive and significant concerns raised in Testimony and included in the Findings of Fact by Commerce DER and No CapX 2020. The ALJ's cut and paste of the Applicant's proposed Findings of Fact does not reflect an independent analysis of evidence in the record.

As the first MISO MVP project applied for in Minnesota, with inherent jurisdictional and cost issues, the project should be vigorously vetted and the record should be fully developed before the Commission considers making a decision. No CapX 2020 requests that the Commission deny the Application, and in the alternative, reject the Recommendation and remand it to the Administrative Law Judge for more thoughtful review.

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20148-102138-02	PUBLIC	12-1053	☐	CN	DOC-DER	REPLY BRIEF--REPLY BRIEF WITH ATTACHMENT A CORRECTED NUMBERING PROPOSED FINDINGS	08/08/2014

I. ITC MIDWEST, LLC IS NOT A PUBLIC SERVICE CORPORATION

The first substantive error is found in FoF 1, p. 2-3, where the Applicants had proposed:

> 1. ITC Midwest is a transmission-only utility that owns approximately 6,600 circuit miles of transmission lines and more than 200 transmission substations in Iowa, Minnesota, Illinois, and Missouri. ITC Midwest is a Minnesota "public service corporation", a "transmission company' and "utility" under state law.[1] ITC Midwest is also a "public utility" under the Federal Power Act. [2]
>
> 1 Minn. Stat. §§ 301B.01, 216B.02, subd. 10; 216E.01, subd. 10.

The ALJ copied verbatim the Applicant's revised Finding of Fact, including the significant and disturbing Finding that ITC Midwest, LLC, is a "public service corporation." This is a false statement. ITC Midwest, LLC, is NOT a "Minnesota public service corporation" under Minnesota law.

The Finding in the ALJ's Recommendation is highlighted below, with the false statement that ITC is a Minnesota public service corporation in yellow:

> 1. ITC Midwest is a transmission-only utility that owns approximately 6,600 circuit miles of transmission lines and more than 200 transmission substations in Iowa, Minnesota, Illinois, and Missouri. ITC Midwest is a ~~Minnesota "public service corporation,"~~ a "transmission company" and "utility" under state law.[2] ITC Midwest is also a "public utility" under Section 203 of the Federal Power Act.[3] As such, ITC Midwest is subject to plenary rate regulation and other oversight by the Federal Energy Regulatory Commission (FERC).
>
> [2] Minn. Stat. §§ 301B.01; 216B.02, subd. 10; and 216E.01, subd. 10.

Applicant ITC Midwest, LLC is NOT a Minnesota "public service corporation." ITC Midwest, LLC, is a private limited liability company organized under Minn. Stat. Ch. 322B[4]. It is a transmission only company, which has the sole purpose of construction and operation of transmission for profit. ITC Midwest, LLC, provides transmission services for utilities,

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[4] Details of ITC Midwest, LLC's organizational filings at the Minnesota Secretary of State's Office are available online: http://mblsportal.sos.state.mn.us/Business/SearchDetails?filingGuid=e2b736fa-90d4-e011-a886-001ec94ffe7f

independent power producers, electric market traders and others utilizing transmission services. A Public Service Corporation would be organized under Minn. Stat. Ch. 302B, the Chapter governing Public Service Corporations. ITC Midwest, LLC, is not organized under Chapter 302B, does not have a franchise to provide electricity to the public, and it has no public purpose.

This error in the Findings of Fact is significant because it is through a grant of a "Certificate of Need" that the "need" required for a public service corporation to condemn land is conferred. For purposes of eminent domain, the Certificate of Need deems infrastructure is needed and with that need demonstration, a "public service corporation" can condemn land for transmission easements. An LLC organized under Minn. Stat. Ch. 322B does not have authority to exercise the power of eminent domain to take land -- only a public service corporation has the power of eminent domain.

> … The corporation may acquire by power of eminent domain the private property necessary or convenient for the transaction of the public business for which it was formed…

Minn. Stat. § 302B.02 (from Minn. Stat. Ch. 302B, Public Service Corporations).

Under the laws of the state of Minnesota, land may not be condemned for a private purpose such as the private purpose of ITC Midwest, LLC:

> **Requirement of public use or public purpose.** Eminent domain may only be used for a public use or public purpose.

Minn. Stat. §117.012, Subd. 2.

This public use requirement is set out more specifically in the Eminent Domain definitions, and expressly limited to "public service corporations" in this section:

> **Public use; public purpose.**
>
> (a) "Public use" or "public purpose" means, exclusively:
> (1) the possession, occupation, ownership, and enjoyment of the land by the general public, or by public agencies;

> **(2) the creation or functioning of a public service corporation**; or
> (3) mitigation of a blighted area, remediation of an environmentally contaminated area, reduction of abandoned property, or removal of a public nuisance.
>
> (b) The public benefits of economic development, including an increase in tax base, tax revenues, employment, or general economic health, do not by themselves constitute a public use or public purpose.

Minn. Stat. §117.025, Subd. 11 (emphasis added).

While a "transmission only" company could arguably be regarded as a "utility" under the Power Plant Siting Act rules, Minn. R. 7850,1000, Subp. 20, an LLC is not included in the definition of utilities found in Minn. Stat. §216E.01, Subd. 10:

> "Utility" shall mean any entity engaged or intending to engage in this state in the generation, transmission, or distribution of electric energy including, but not limited to, a private investor-owned utility, cooperatively owned utility, and a public or municipally owned utility.

Minn. Stat. §216E.01, Subd. 10. There is no statutory authority for the addition of transmission companies to the definition of "utility" in Minnesota Rules. The definition of "transmission companies" cited by the ALJ specifically separates and distinguishes between "transmission companies" and excludes "transmission companies" from consideration as utilities:

> **Transmission company**. "Transmission company" means persons, corporations, or other legal entities and their lessees, trustees, and receivers, engaged in the business of owning, operating, maintaining, or controlling in this state equipment or facilities for furnishing electric transmission service in Minnesota, ***but does not include public utilities, municipal electric utilities, municipal power agencies, cooperative electric associations, or generation and transmission cooperative power associations.***

Minn. Stat. §216B.02, Subd. 10 (emphasis added).

The statement in the ALJ's Finding of Fact 1 that Applicant ITC Midwest, LLC, is a Public Service Corporation is incorrect under Minn. Stat. Ch. 216B, Ch. 216E, and Ch. 302, and that part of the Finding of Fact must be removed. See Exceptions to ALJ's Recommendation – Findings of Fact for specific language below this narrative.

II. <u>**ITC MIDWEST WILL NEED TO ACQUIRE ADDITIONAL RIGHT-OF-WAY.**</u>

The ALJ's Recommendation contains a two FoF section about Right-of-Way, and this is a logical place to note that additional right-of-way must be acquired for this project.

> 123. ITC has proposed a right-of-way of 200 feet for the project. <u>ITC will need to acquire additional right-of-way for this project</u>. Within the 200 foot right-of-way…

The Applicant is not a public service corporation, so the fact that new Right-of-Way will be required should be noted because it is unclear how it would obtain that Right-of-Way.

III. <u>**THE ALJ'S RECOMMENDATION CONTAINS ONLY FOUR FINDINGS ON COST, OMITTING MATERIAL ASPECTS OF THE COST CONSIDERATION.**</u>

There is no basis in the record for any cost estimate. As DOC DER notes, "The ALJ and Commission must reject ITC's calculations or quantifications that are grounded on the very cost estimates that ITC itself rejects as unreliable." DOC DER Exceptions, p. 3. The ALJ's Recommendation, Findings of Fact 125 – 128 and 258-263, not only presents information as facts that are not, but it gives ITC Midwest a free pass to use a 30% contingency, twice that of typical contingency percentage found in other transmission projects. The ALJ also only references the "total annual first year revenue requirement" and not the full 20 year term costs, and only considers "approximately $7.0 million" to be paid by Minnesota ratepayers which is without basis. FoF 128, 260. The ALJ does not total the costs, for all of MVP 3 or all 17 MISO MVP projects, and only addresses one year, the first year, of twenty years of cost allocation for the revenue requirement.

Another way to look at costs is to refer to Schedule 26, used to calculate payments from 2015 – 2034, 20 years. Even by the ALJ's calculation of only this ITC Midwest project (1/2 of MVP 3), the cost to Minnesotans would be roughly $140 million over 20 years. Because Minnesotan's must pay the 13.3% of EACH and ALL of the MVP Portfolio Projects, the cost will be 13.3% of $5,821,866,035.00 x 13.3% = $702,488,812.00, which does not include the 12.38% rate of return.

This is the first MISO MVP project to be applied for and considered by the Commission. The MISO MVP projects are interconnected and interdependent – all were studied together and all are required to achieve the benefits claimed. The PROMOD modeling assumes in its study case that all 17 MVPs are inservice. This is not offered as a menu, one in Minnesota, none in Iowa. This ITC Midwest project is just a part, roughly ½ of MVP 3. The Applicant testified 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. No CapX 2020 agrees.

Costs of the MVP Project were estimated and considered as a part of the MISO MTEP process for MTEP 11. The project cost of the isolated ITC Midwest portion of this MN/IA project was estimated at $194-206 million, later at $273-285; initially it was estimated at $271-283 million for all of MVP 3; $1.71-1.8 billion for MVP 3 & 4; $5.2 -5.8 billion for the 17 MVP Portfolio; and alternately, $8.8 -16.4 billion when totaling revenue requirements for the 17 MVP projects.

The project cost, for this distinct ITC Midwest MN/IA project and also for the entire MVP Portfolio, will be paid by utilities utilizing the wholesale transfer services provided by these projects. For Minnesota ratepayers, the cost is estimated to be a 13.3% share of the MVP 17 project portfolio capital costs of $5,821,866,035, or $774,308,182.65 for Minnesota ratepayers. 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 the full Portfolio range of benefits, from those of MVP 3 and 4 to claimed benefits achieved only with the full 17 MVP Portfolio. In consideration of the range of benefits, the Commission must also take into account the full range of costs and impacts associated with the full MVP Portfolio necessary to provide these benefits, and not "just" the cost of the ITC Midwest MN/IA project, not "just" MVP projects 3 and 4 and 5, but also the full range of $5,821,866,035 of MVP costs attributable to Minnesota ratepayers and the associated environmental impact costs.

The ALJ also conflates the costs of MVP 3 and "the Project," roughly ½ of MVP 3, and makes comparisons of unlike costs. These misleading Findings of Fact should be corrected so that comparisons may be made:

> 259. While the capital cost for the 161 kV Rebuild Alternative is less than the Project, the cost allocation of MVP Project 3 compared to the 161 kV Rebuild Alternative is materially different.[420] This is because "the Project" is only roughly ½ of MVP 3.
>
> 260. The costs of MVP Projects, including MVP Project 3, are allocated across the MISO Midwest footprint, with approximately 13.3 percent recovered from Minnesota's network load under MISO's allocation formula.[421] Accordingly, the approximately $6.8 million estimated annual revenue requirement for the Project would be spread across all Minnesota MISO load.[422] The approximately $____ million estimated annual revenue requirement for MVP 3 would be spread across all Minnesota MISO load. Id. The approximately $____ million estimated annual revenue requirement for the MISO MVP Portfolio would be spread across all Minnesota MISO laod. Id. ITC Midwest's zonal network customers in Minnesota would pay four percent, approximately $279,000, of Minnesota's portion.[423] ITC Midwest's zonal network customers in Minnesota would also pay 14 percent of the associated zonal revenue requirement, an additional $169,000 for the associated facilities.[424] In contrast, as a baseline reliability project, the 161 kV Rebuild Alternative would be assigned 100 percent—the entire $8.5 million annual revenue requirement—to ITC Midwest's customers.[425]

The ALJ's Findings should be amended as follows to include information regarding the full range MVP costs and ratepayer costs and also concerns raised by Commerce DER. No CapX 2020 amendments are in red ~~strikeout~~/underline:

125. The final cost of the entire MN-IA 345 kV Project is highly dependent on a number of factors that are outside of ITC Midwest's control, including the final route (which impacts final design); the timing of construction; and availability of construction crews, and the cost of materials.[163] In light of these uncertainties, ITC Midwest provided approximate Project costs using a bandwidth of plus/minus 30 percent.[164] A more typical contingency range for a transmission project is plus/minus 15%. ~~The midpoint values of these estimated total Project cost ranges are provided in the table below:~~

~~Project Costs ($ Millions) Minnesota Route~~	~~Minnesota Cost of Construction165*~~	~~Iowa Cost of Construction166~~	~~Total Project Cost167~~
~~Route A~~	~~$208~~	~~$77~~	~~$285~~
~~Route B168~~	~~$196~~	~~$77~~	~~$273~~
~~Modified Route A~~	~~$207~~	~~$77~~	~~$284~~

~~*Cost of construction includes re-locating associated facilities from Winnebago Junction Substation to the Proposed Huntley Substation~~

126. ~~All but $7.4 million of the ITC Midwest costs for MVP 3 will be recovered regionally through MISO Schedule 26A charges. These~~ Charges to ratepayers are based upon the MVP Usage Rate ("MUR") as calculated pursuant to Attachment MM of the MISO Tariff. A key component of the MUR is the MVP revenue requirement of each MVP Transmission-Owning Member of MISO. Minnesota ratepayers' share of the annual revenue requirement is determined by the percent of total energy in the MISO Classic footprint169 used in Minnesota, which has been estimated at approximately 13.3 percent based on MISO's posted 2010 energy withdrawal data.[170] The MVP revenue requirement is calculated pursuant to a formula provided for in Attachment MM of the MISO Tariff. To ensure public review of the calculation of each MVP owner's calculation of its revenue requirement, Section 2(g) of Attachment MM requires public posting to the MISO OASIS of its revenue requirement calculation.[171]

127. The determination of the MVP revenue requirement is based on a series of inputs from ITC Midwest's Attachment O formula rate. In

> calculating the Attachment O formula rate, the MISO Tariff provides for information sharing procedures and review [31853/1]
> by interested parties. The MISO Tariff, Attachment O, explicitly identifies state regulatory commissions as interested parties and provides them standing to both conduct discovery and challenge calculation of the inputs to the formula rate at FERC.[172] The record does not contain information regarding Minnesota's participation or position, if any, in these rate dockets.
>
> 128. The total annual first year revenue requirement for the Project will be approximately $52.4 million.[173] Of this amount, approximately $7.0 million will be collected from Minnesota ratepayers.[174] Under Schedule 26A, the annual revenue requirement will be collected each year for a 20 year term, from 2015 -2034.

No CapX 2020 urges the Commission to adopt DOC DER's position that the record does not support the ALJ's proposed Findings regarding "project costs, estimated costs, savings to ratepayers, likely costs to ratepayers, etc."

IV. THE RECORD DOES NOT CONTAIN DISTINCT IDENTIFICATION OF BENEFITS TO MINNESOTA.

The ALJ's Recommendation misconstrues the economic benefits of the project claimed by ITC Midwest with the statutory criteria regarding benefits of the project – economic benefits are not the "benefits" anticipated. Further, benefits claimed attributable to this project are not identified by benefits to Minnesota, nor is it acknowledged that the benefits claimed require that all 17 MVP projects be built.

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). However, these benefits are not the type referred to as benefits of the MISO MVP Projects.

Commerce Data Requests procured responses to Data Requests that show the levels of dependence of MVP 3 on MVP 4 and MVP 5 to provide benefits, and these were not taken into account by the ALJ. Nor did the ALJ take into account that the modeling for the MISO MVP Portfolio relies on ALL projects being built to achieve the benefits – that individual project benefits were not calculated nor part of the MISO MVP Portfolio development.

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.[5]

More importantly, it does not independently 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.[6]

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 <u>with</u> MVP 5 is shown for "Cost Change Due to MVP 3 only" as a difference ranging from -0.2% to -

[5] Ex. 33, Schatzki Rebuttal, Schedule 2 (attached).
[6] Ex. 33, Schatzki Rebuttal, Schedule 2, p. 7 of 36.

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.

The only finding regarding these "benefits" is Finding of Fact 261:

> 261. Dr. Schatzki's analysis also shows that the Project offers more net benefits relative to the 161 kV Rebuild Alternative when other costs and benefits are considered. These costs and benefits include transmission construction costs, changes in production costs, and changes in the social cost of aggregate emissions.[426] With MVP 5 in service, the annual net benefits of MVP 3 and 4 (relative to the 161 kV Rebuild Alternative) range from $9.1 million to $30.6 million.[427] With MVP 5 in service, the annual net benefits of MVP 3 alone (relative to the 161 kV Rebuild Alternative) range from $8.6 million to $22.7 million.[428] 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.[429] The benefits of "the project," which is essentially one-half of MVP three accrue at these amounts only with the other half of MVP 3 modeled, plus the addition of MVP 4 and/or MVP 5.

Applicants fail to demonstrate a substantive benefit to Minnesota. The Findings of Facts must address the reliance and interdependence of the MVP projects to provide benefits.

V. **IT'S NOT FOR WIND**

This project is not for wind. One need look no further than 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.[7]

This material fact was overlooked by the ALJ, and must be added to the Findings of Fact.

The record also demonstrates that this project will not displace coal. MISO's own MTEP 11, describing the MVP 17 project Portfolio, shows that there's an infinitesimal 0.85% decrease in coal, not even close to a direct displacement:

[7] MISO's Chatterjee, Evidentiary Hearing, Tr. p. 94-95.

		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 a cost of over $5.2 billion, will result in an estimated -0.85% decrease in MWH of coal generation. It will have a negligible impact on decrease of generation by coal. These facts must be added to the Findings of Fact.

VI. <u>THE RECOMMENDATION MISSATES THE PURPOSE OF THIS PROJECT AND THE SW MN 345 Kv (PUC Docket 01-1958) AS "825 MW" FOR WIND</u>

The ALJ's Recommendation refers to "ELECTRICAL SYSTEM IN PROJECT AREA AND PRIOR STUDY WORK, and states that:

139. The electrical system in the Project area was designed to serve the residential and commercial needs of rural southwest Minnesota.[195]

There have been significant modifications for bulk power transfer made, as noted, and Finding of Fact 139 should instead read:

139. The electrical system in the Project area and in the region was originally designed to serve the residential and commercial needs of customers in utility service territories. Substantial changes have been made both in this region and locally to facilitate bulk power transfer.

142**. Wind generation development has quickly outstripped the capability of the transmission system in southwest Minnesota** and it has become apparent that the electrical system designed primarily to serve local load was ill-suited to meet the additional demands of wind generation. The same year the Legislature passed Minn. Stat. § 216B.1691, **Xcel Energy proposed a major investment involving multiple transmission lines ("825 Projects") to increase outlet capability on the Buffalo Ridge to 825 MW.**[200] At that time, there was 300 MW of wind generation installed.[201]

The ALJ refers to that docket as the "825 Projects" and misconstrues and misrepresents the purpose, operation, and Order. The transmission line is not "for wind," as it legally must serve whatever generation is on the grid. Further, the testimony of NSP/Xcel's Rick Gonzalez regarding the powerflows for that project showed that with the 50/50 North/South option only 213 MW of wind generation would flow from the one substation into that 2,250 MVA line, and that for the 100/0 South/North option, only 302 MW maximum.[8]

There is also misunderstanding or myth surrounding the "825 MW" number, which was not a literal capacity increase proposed, ordered, or achieved for the proposed transmission line. Instead, it originated with the wind mandate of the 1994 Prairie Island Agreement and legislation and then followed by the 1999 Merger Agreement between the self-branded "Clean Energy Intervenors" in the ITC Docket and NSP:

[8] See attached powerflows from I-H, PUC Docket 01-1958.

> 4. NSP agrees to undertake the necessary transmission studies with respect to upgrades needed to move additional increments of up to a total of 825 MW of wind generation from within the State of Minnesota, subject to the requirements and procedures of FERC Order 888/889. Upon review of the most feasible transmission alternatives, NSP agrees that it will seek all necessary regulatory approvals, including regional transmission planning approvals, and will file for a Certificate of Need and/or Environmental Impact Statement, as required by law, by July, 2001, unless the requirements for filing have not been satisfied, such that a filing made on this date would not satisfy the Minnesota Public Utilities Commission's requirements for Certificate of Need filings, in which case the filing shall be made within a reasonable period thereafter. In the event that wind resources are not procured in an all-source bidding scheduled for 2000 or 2001, NSP agrees to provide an assessment of the impediments to wind in an all-source bidding process in its July 1, 2002 resource plan. The Parties agree to work together to remove the identified impediments to wind energy with the intention of improving its performance in subsequent all-source bidding processes. Efforts to remove the identified impediments may include, but are not limited to, legislative initiatives to lower costs, initiatives to improve wind accreditation, identification of preferred sites for wind developments, and improvements to wind forecasting to address operational issues. Nothing in this provision waives either Parties' right to argue their position regarding wind procurement before the MPUC in future Resource Plan proceedings.

See para. 4, 1999 Merger Agreement, PUC Docket E,G002/PA-99-1031.[9]

Just before the 2001 NSP/Xcel filing for the SW MN 345 kV lines, Lignite Vision 21 also proposed the Split Rock-Lakefield Jct. line as part of its agenda to move new coal eastward for export. The ABB Lignite Vision 21 transmission development and marketing plan and Phase II Transmission System Impact Study Summary Report, dated February and November, 2001,[10] and entered in the PUC Docket 01-1958 record, proposed transmission "to assist in the development of additional lignite-based electrical generation in North Dakota," to expressly to "increase North Dakota export."

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[9] Filed in ITC Midwest Docket 12-1053, filed as NoCapX 2020/CETF Comment, Exhibit G, Merger Agreement.

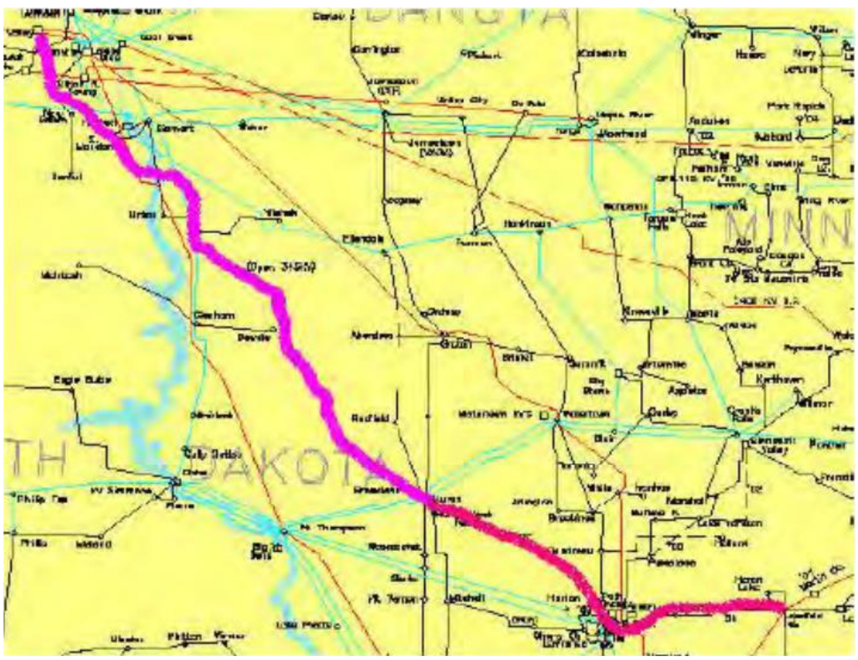
20145-100009-01	PUBLIC	12-1053	☐	CN	CETF AND NO CAPX 2020	COMMENTS--COMMENT AFFIDAVIT	05/30/2014
20145-100009-07	PUBLIC	12-1053	☐	CN	CETF AND NO CAPX 2020	COMMENTS--EXHIBITS C - N	05/30/2014

[10] See Affidavit of Overland, para. 9, and its attached Exhibit E:

20145-100009-01	PUBLIC	12-1053	☐	CN	CETF AND NO CAPX 2020	COMMENTS--COMMENT AFFIDAVIT	05/30/2014
20145-100009-07	PUBLIC	12-1053	☐	CN	CETF AND NO CAPX 2020	COMMENTS--EXHIBITS C - N	05/30/2014

Initially studies were made for identifying the common facilities required to export 2,450 MW from North Dakota with the new Lignite Vision 21 500-MW power plant. Studies were also made for identifying the facilities required to export 2,800 MW from North Dakota with the new Lignite Vision 21 500-MW power plant plus an additional 350 MW in transmission reservations.

Id. A common factor is the "70-mile, 345 kV circuit between Split Rock and Lakefield Junction," repeatedly referred to by the ALJ in his ITC Midwest Recommendation, and to which this project will connect. The Split Rock – Lakefield Junction line is on the lower right portion of this map, and the ITC Midwest line would extend eastward from Lakefield Junction:



In the Split Rock-Lakefield Jct. docket (01-1958), the TLTG tables[11] showed that the system was at least 1,475 MW deficient, due to interconnection of generation such as wind and natural gas in the area, without the requirement of network upgrades to handle the generation. Cumulative expenditures of $138,363,000 had to be spent on upgrades and rebuilds in the existing system, with the biggest increase in capacity, 615 MW, at the outset with rebuild of the Wilmarth-Martin Co. 345 kV line that had been a problem since it was designed and built. It

[11] See attached TLTG Table, PUC Docket 01-1958.

was not until 13 rebuilds and reconductoring upgrades that the "base package" was added to bring the system to "0," and that base package included nearly $6 million for the long problematic Ft. Calhoun interface in **NEBRASKA**! It was not until this $138,364,000 was spent that any increased capacity could be realized. This SW MN 345 kV 01-1958 docket was NOT about transmission for wind, it was catch-up due to interconnection of incremental additions of natural gas and wind generation without necessary transmission upgrades.

The Recommendation cited by the ALJ requires that 468 MW of Power Purchase Agreements be declared Network Resources, to assure it has transmission service available.

To further demonstrate that this project is not for wind, one need look no further than the statements of MISO witness Chatterjee, who testified 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.

VII. THE RECOMMENDATION MISINTERPRETS THE PURPOSE OF SPECIAL PROTECTION SYSTEMS.

The Recommendation adopts wholesale the Applicant's disfavor of Special Protection Systems (SPS), despite the fact, established in the record, that "forbidding any new SPSs" is an ITC Midwest policy, and not a MISO, NERC, or FERC requirement. See FoF 154, citing CoN Application, Ex. 6 at 66-67. SPSs, formerly Operating Guides, are designed to allow safe operation of the transmission system if congested. Commerce reviewed the SPS situation in detail through Information Requests. See Ex. 202, Heinen Direct, p. 8-10.

Applicants 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”. 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.

The Applicants rely on the constraints present in the Fox Lake line and use of a “System Protection Scheme” to satisfy MISO Criteria 3, 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.

VIII. FINDINGS IMPROPERLY RELIED ON COMMENTS THAT WERE NOT MADE UNDER OATH

At the public hearing, the ALJ was requested to offer commentors the opportunity to make comments under oath. He declined, said he would not offer the option of testifying under oath, and refused to put that decision on the record. Minn. Stat. §1400.7200; Minn. R. 7850.3800, subp. 2.

> All evidentiary testimony presented to prove or disprove a fact at issue shall be under oath or affirmation.

Minn. Stat. §1400.7800.

None of the public statements made at the public hearing were under oath.[12]

[12] See Transcripts, Blue Earth, May 13, 2014; Fairmont May 14, 2014; Evidentiary Hearing May 20, 2014.

Ostensibly based on unsworn testimony at the public hearing regarding the Odell wind project, without any cross-examination or verification, Dr. Rakow changed his testimony the evening before the evidentiary hearing was to begin. All Findings of Fact based on that testimony cannot be relied on and the Findings of Fact must be stricken.

~~190. Justin Pickar, Director of Development at Geronimo Energy, also testified regarding the need for the Project. Geronimo Energy has an interest in projects that have PPAs approved by the MPUC that are dependent on the Minnesota – Iowa 345 kV line being built.283 Mr. Pickar testified about the impacts that denial of this Certificate of Need would have on Geronimo Energy's Odell wind farm.284 According to Mr. Pickar, "[t]he direct impact from our wind farm's going to bring around $50 million over 20 years and 10 to 12 good-paying full-time jobs to the area. So we support the ITC 345 kV MVP line being built and see the need."[285]~~

Additional testimony not sworn on oath was provided by Brad Haupert and Adam Sokolski. This testimony was not verified, and was relied on by the ALJ and these Findings of Fact, and as such, should also be stricken:

~~189. For example, Shannelle Montana, representing EDF Renewable Development, testified about the benefits the communities in southwestern Minnesota would realize as a result of wind development projects.[279] EDF Renewable Development was involved with projects, including the Lakefield Wind Project and the Nobles and Fenton Projects. Ms. Montana testified that many of the communities in which EDF Renewable Development has been working have been asking for more development as a result of the economic benefits, job creation, and increase in tax money going back to these same communities.[280] Ms. Montana further testified that the MVP lines, particularly the Minnesota – Iowa 345 kV line, "is very important for us to continue developing."[281] Ms. Montana explained that transmission was necessary to increase development "to get the power from our project areas to more densely populated areas" which "allows us to sell the project and have a successful project."[282]~~

~~191. Brad Haupert, a site supervisor for Vestas, also testified regarding need for the Project. Vestas has wind turbines in the upper Midwest, including southern Minnesota and northern Iowa where it has 100 employees in the region.286 Mr. Haupert discussed the job opportunities that wind development has brought to the area.287 Mr. Haupert testified that there was very little opportunity "until the wind industry came into the area and offered a lot of very good-paying jobs for many people in the area."288 Mr. Haupert further elaborated that these jobs brought with them good benefits, stability, and a higher rate of income.289~~

~~192. Mr. Sokolski, a business developer at Iberdrola Renewables, also submitted comments to supplement his testimony at the public hearing on May 14, 2014. Iberdrola Renewables owns and operates the Trimont, Elm Creek, and Elm Creek II wind~~

~~projects.290 In addition to the community benefits and job growth discussed by other witnesses, Mr. Sokolski addressed the need for MVP 3 in the area for the wind industry to continue to develop:~~

> ~~Denial of the project will increase the cost of a future transmission project to provide the multiple benefits of the proposed project by pushing off the capital and labor costs into the future, when materials and labor will be more expensive than they are today." Mr. Sokolski stated that denying the Project would not solve any of the existing problems on the local transmission system facilities "which are frequently overloaded causing curtailment of wind production.291 facilities "which are frequently overloaded causing curtailment of wind production.~~[~~291~~]

IX. **MISO MVP ANALYSIS IN SUPPORT OF THIS PROJECT IS NOT CREDIBLE**

No CapX 2020 adopts the DOC DER position regarding the ALJ Recommendation's unfounded reliance on the MISO analysis underlying the ITC Midwest project proposal as if fully related herein. In short, from the DOC DER Exceptions:

> As Dr. Rakow explained, MISO essentially combined a short, cost effective segment with other short, non-cost effective segments to create larger transmission projects that could be cost effective when considered together. In essence the cost-effective Lakefield Junction—Rutland segment was used to subsidize other segments of a larger project that were not cost effective. However, one lesson of MTEP10 is that, in this instance, other shorter more localized alternative perform better economically than longer alternatives. This result is demonstrated by the fact that, in MTEP10, only the 2nd Fox Lake—Rutland—Winnebago 161 kV alternative (with a ratio of 10.23) had a benefit/cost ration greater than 1.

Further, MISO did not bring forward the results from one year to the next, and the cumulative results were not considered, skewing the MTEP "study" results, in favor of lines suitable for bulk power transfer.

X. **NO CAPX 2020 REQUESTS DENIAL OF THE APPLICATION, AND IN THE ALTERNATIVE, REMAND TO THE ALJ FOR MORE THAN A CUT AND PASTE OF APPLICANT'S PROPOSED FINDINGS OF FACT.**

No CapX 2020 requests that the Certificate of Need be denied because the Applicant has not met its burden of proof and production, and in the alternative, that it be remanded to the

Administrative Law Judge to build the record and for more thoughtful analysis. No CapX 2020 also requests oral argument in this docket when it comes before the Commission.

September 23, 2014

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EXCEPTIONS TO ALJ'S RECOMMENDATION

FINDINGS OF FACT

1. ITC Midwest is a transmission-only utility that owns approximately 6,600 circuit miles of transmission lines and more than 200 transmission substations in Iowa, Minnesota, Illinois, and Missouri. ITC Midwest is a "transmission company" and "utility" under state law.[2] ITC Midwest is also a "public utility" under Section 203 of the Federal Power Act.[3] As such, ITC Midwest is subject to plenary rate regulation and other oversight by the Federal Energy Regulatory Commission (FERC).

123. ITC has proposed a right-of-way of 200 feet for the project. ITC will need to acquire additional right-of-way for this project. Within the 200 foot right-of-way…

139. The electrical system in the Project area and in the region was originally designed to serve the residential and commercial needs of customers in utility service territories. Substantial changes have been made both in this region and locally in the project area to facilitate bulk power transfer.

RE: Special Protection System

14. ITC stated that the proposed Project is designed to relieve transmission constraints in southwestern Minnesota and northern Iowa areas. ITC stated that the proposed Project would also facilitate the movement of energy associated with renewable resources to markets outside the local area.[13]

15. ITC stated in the Petition that there are currently two special protection systems (SPSs) imposed by MISO on ITC's system in southwestern Minnesota:

- the Fieldon Capacitor Bypass SPS (Fieldon SPS) and
- the Nobles County—Wilmarth SPS (Wilmarth SPS).

The Fieldon SPS has been in-place since 2001 and the Wilmarth SPS has been in-place since 2007.[14]

[13] ITC Ex. 22 at 5-12 (Berry Direct).
[14] ITC Ex. 6 at Appendix J, pages 17-18 (Petition).

16. ITC's view is that an SPS is a remedial operating solution to a transmission reliability violation, often resulting from the installation of new facilities which either aggravate an existing transmission violation or initiate a new violation. ITC's experience is that SPSs are generally undesirable because they can lead to exponential growth in demands placed on the transmission system and create operational complexities.[15]

17. ITC stated that the results of the Company's analysis suggest that both SPSs would be retired if MVP 3 were constructed. However, ITC also noted that MISO makes the final determination of whether an SPS should or should not be retired.[16]

18. One of ITC's claimed needs is to relieve SPSs in southwestern Minnesota. Because these SPS are currently in existence, the accuracy of ITC's forecast of future demand for the type of energy that would be supplied by the proposed facility is not relevant. That is, one of the claimed needs is to alleviate problems that currently exist, rather than the claimed need being based on a potential future state of the electrical system.

19. Regarding transmission issues in general, Department witness Mr. Adam Heinen's analysis of recent operations estimated that there were 12 constraints, for a total of 1,981 hours, in calendar year 2011 and 3 constraints, for a total of 1,242 hours, in calendar year 2012 for the area near the proposed Project. Based on this analysis of historical data Mr. Heinen concluded that the number and magnitude of constraints suggest that additional transmission capacity is needed.[17] Mr. Heinen reasonably concluded that "construction of a transmission line in the Project area would likely improve deliverability and reduce constraints on the transmission system."[18]

20. Three separate witnesses addressed Mr. Heinen's questions regarding the SPSs in Rebuttal Testimony:

- Mr. Randall Porter for CEI;
- Mr. Diguanto Chatterjee for MISO; and
- Mr. Joe Berry for ITC.

21. Mr. Heinen's surrebuttal reasonably concluded that ITC witness Mr. Berry did not address why MISO labeled the SPSs in the area of MVP 3 as inactive or whether reliability concerns still exist. Mr. Heinen reasonably concluded that, in ITC's estimation, either the 161 kV Rebuild alternative or the proposed MVP 3 could relieve

[15] ITC Ex. 6 at Appendix J, page 18 (Petition).
[16] ITC Ex. 6 at Appendix J, page 19 (Petition).
[17] DOC-DER Ex. 200 at 7 (Heinen Direct).
[18] DOC DER Ex. 200 at 14 (Heinen Direct).

the two SPSs in the southwestern Minnesota and Northern Iowa areas.[19] However, Mr. Heinen stated that he was:

> … unable to identify a definitive statement regarding future retirement of SPS conditions. Also of note, ITCM Witness Berry suggests that construction of the 161 kV rebuild alternative also has the potential to relieve SPS conditions in the Project Area.[20]

22. Mr. Heinen interpreted MISO witness Mr. Chatterjee's rebuttal as indicating that even though an active SPS is not required in 2015, and thus is designated inactive, based on MISO's transmission modeling assumptions the thermal loading concerns are still present and need to be relieved by a transmission project at some point in time.[21]

122. 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.[22]

123. ITC has proposed a right-of-way of 200 feet for the project. ITC will need to acquire additional right-of-way for this project. Within the 200 foot right-of-way…

> 125. The final cost of the entire MN-IA 345 kV Project is highly dependent on a number of factors that are outside of ITC Midwest's control, including the final route (which impacts final design); the timing of construction; and availability of construction crews, and the cost of materials.[163] In light of these uncertainties, ITC Midwest provided approximate Project costs using a bandwidth of plus/minus 30 percent.[164] A more typical contingency range for a transmission project is plus/minus

[19] DOC-DER Ex. 202 at 3 (Heinen Surrebuttal).
[20] DOC-DER Ex. 202 at 6 (Heinen Surrebuttal).
[21] DOC-DER Ex. 202 at 5 (Heinen Surrebuttal).
[22] MISO's Chatterjee, Evidentiary Hearing, Tr. p. 94-95.

15%. ~~The midpoint values of these estimated total Project cost ranges are provided in the table below:~~

~~**Project Costs ($ Millions) Minnesota Route**~~	~~**Minnesota Cost of Construction**~~~~[165*]~~	~~**Iowa Cost of Construction**~~~~[166]~~	~~**Total Project Cost**~~~~[167]~~
~~Route A~~	~~$208~~	~~$77~~	~~$285~~
~~Route B168~~	~~$196~~	~~$77~~	~~$273~~
~~Modified Route A~~	~~$207~~	~~$77~~	~~$284~~

~~*****Cost of construction includes re-locating associated facilities from Winnebago Junction Substation to the Proposed Huntley Substation~~

126. ~~All but $7.4 million of the ITC Midwest costs for MVP 3 will be recovered regionally through MISO Schedule 26A charges. These~~ Charges to ratepayers are based upon the MVP Usage Rate ("MUR") as calculated pursuant to Attachment MM of the MISO Tariff. A key component of the MUR is the MVP revenue requirement of each MVP Transmission-Owning Member of MISO. Minnesota ratepayers' share of the annual revenue requirement is determined by the percent of total energy in the MISO Classic footprint169 used in Minnesota, which has been estimated at approximately 13.3 percent based on MISO's posted 2010 energy withdrawal data.[170] The MVP revenue requirement is calculated pursuant to a formula provided for in Attachment MM of the MISO Tariff. To ensure public review of the calculation of each MVP owner's calculation of its revenue requirement, Section 2(g) of Attachment MM requires public posting to the MISO OASIS of its revenue requirement calculation.[171]

127. The determination of the MVP revenue requirement is based on a series of inputs from ITC Midwest's Attachment O formula rate. In calculating the Attachment O formula rate, the MISO Tariff provides for information sharing procedures and review [31853/1]
by interested parties. The MISO Tariff, Attachment O, explicitly identifies state regulatory commissions as interested parties and provides them standing to both conduct discovery and challenge calculation of the inputs to the formula rate at FERC.[172] The record does not contain information regarding Minnesota's participation or position, if any, in these rate dockets.

128. The total annual first year revenue requirement for the Project will be approximately $52.4 million.[173] Of this amount, approximately $7.0 million will be collected from Minnesota ratepayers.[174] Under Schedule 26A, the annual revenue requirement will be collected each year for a 20 year term, from 2015 -2034.

139. The electrical system in the Project area and in the region was originally designed to serve the residential and commercial needs of customers in utility service territories. Substantial changes have been made both in this region and locally to facilitate bulk power transfer.

XXX. The ITC Midwest project and the entire 17 project MISO MVP Portfolio, at a cost of over $5.2 billion, will result in an estimated -0.85% decrease in MWH of coal generation. It will have a negligible impact on decrease of generation by coal.[23]

XXX. MISO's Chatterjee testified that the purpose of the project is moving baseload generation and that wind is a very small part of it:

> 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.[24]

157. ~~MVP 3 enhances the reliability of the regional bulk transmission system by creating a new 345 kV transmission tie between Minnesota and Iowa to meet the increasing demands placed on the system, including demands by wind energy resources.[223] Wind generation, because of its intermittent operation, adds to the operational variability and uncertainty inherent in all power systems. This reliability concern is significantly reduced with a robust grid which allows the benefits of diversity to be realized (geographic, resource, and load).[224]~~

157. Benefits are claimed in decreased LMP cost. These lower costs from the ITC Midwest portion of MVP 3, and of MVP 3 are nominal, and dependent on MVP 4 and MVP 5.[25]

> More importantly, it does not independently 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

[23] Ex. __, MISO MTEP 11, Table 2.5-6.
[24] MISO's Chatterjee, Evidentiary Hrg., Tr. p. 94-95.

[25] Ex. 33, Schatzki Rebuttal, Schedule 2 (attached).

hubs in eastern Iowa, along with providing reliability and congestion relief benefits."[26]

158. 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. The record does not identify a distinct benefit for Minnesota.

159. 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 at less than 1% are negligible. There is no breakdown of benefit to Minnesota, and the small percentage is shown as a benefit is for the entire MISO footprint. The record does not identify a distinct benefit for Minnesota.

~~190. Justin Pickar, Director of Development at Geronimo Energy, also testified regarding the need for the Project. Geronimo Energy has an interest in projects that have PPAs approved by the MPUC that are dependent on the Minnesota – Iowa 345 kV line being built.283 Mr. Pickar testified about the impacts that denial of this Certificate of Need would have on Geronimo Energy's Odell wind farm.284 According to Mr. Pickar, "[t]he direct impact from our wind farm's going to bring around $50 million over 20 years and 10 to 12 good-paying full-time jobs to the area. So we support the ITC 345 kV MVP line being built and see the need."[285]~~

~~189. For example, Shannelle Montana, representing EDF Renewable Development, testified about the benefits the communities in southwestern Minnesota would realize as a result of wind development projects.[279] EDF Renewable Development was involved with projects, including the Lakefield Wind Project and the Nobles and Fenton Projects. Ms. Montana testified that many of the communities in which EDF Renewable Development has been working have been asking for more development as a result of the economic benefits, job creation, and increase in tax money going back to these same communities.[280] Ms. Montana further testified that the MVP lines, particularly the Minnesota – Iowa 345 kV line, "is very important for us to continue developing."[281] Ms. Montana explained that transmission was necessary to increase development "to get the power from our project areas to more densely populated areas" which "allows us to sell the project and have a successful project."[282]~~

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

~~191. Brad Haupert, a site supervisor for Vestas, also testified regarding need for the Project. Vestas has wind turbines in the upper Midwest, including southern Minnesota and northern Iowa where it has 100 employees in the region.286 Mr. Haupert discussed the job opportunities that wind development has brought to the area.287 Mr. Haupert testified that there was very little opportunity "until the wind industry came into the area and offered a lot of very good-paying jobs for many people in the area."288 Mr. Haupert further elaborated that these jobs brought with them good benefits, stability, and a higher rate of income.289~~

~~192. Mr. Sokolski, a business developer at Iberdrola Renewables, also submitted comments to supplement his testimony at the public hearing on May 14, 2014. Iberdrola Renewables owns and operates the Trimont, Elm Creek, and Elm Creek II wind projects.290 In addition to the community benefits and job growth discussed by other witnesses, Mr. Sokolski addressed the need for MVP 3 in the area for the wind industry to continue to develop:~~

> ~~Denial of the project will increase the cost of a future transmission project to provide the multiple benefits of the proposed project by pushing off the capital and labor costs into the future, when materials and labor will be more expensive than they are today." Mr. Sokolski stated that denying the Project would not solve any of the existing problems on the local transmission system facilities "which are frequently overloaded causing curtailment of wind production.291 facilities "which are frequently overloaded causing curtailment of wind production.[291]~~

259. While the capital cost for the 161 kV Rebuild Alternative is less than the Project, the cost allocation of MVP Project 3 compared to the 161 kV Rebuild Alternative is materially different.[420] This is because "the Project" is only roughly ½ of MVP 3.

260. The costs of MVP Projects, including MVP Project 3, are allocated across the MISO Midwest footprint, with approximately 13.3 percent recovered from Minnesota's network load under MISO's allocation formula.421 Accordingly, the approximately $6.8 million estimated annual revenue requirement for the Project would be spread across all Minnesota MISO load.422 The approximately $____ million estimated annual revenue requirement for MVP 3 would be spread across all Minnesota MISO load. Id. The approximately $____ million estimated annual revenue requirement for the MISO MVP Portfolio would be spread across all Minnesota MISO laod. Id. ITC Midwest's zonal network customers in Minnesota would pay four percent, approximately $279,000, of Minnesota's portion.423 ITC Midwest's zonal network customers in Minnesota would also pay 14 percent of the associated zonal revenue requirement, an additional $169,000 for the associated facilities.424 In contrast, as a baseline reliability project, the 161 kV Rebuild Alternative would be assigned 100 percent—the entire $8.5 million annual revenue requirement—to ITC Midwest's customers.425

261. Dr. Schatzki's analysis also shows that the Project offers more net benefits relative to the 161 kV Rebuild Alternative when other costs and benefits are considered. These

costs and benefits include transmission construction costs, changes in production costs, and changes in the social cost of aggregate emissions.[426] With MVP 5 in service, the annual net benefits of MVP 3 and 4 (relative to the 161 kV Rebuild Alternative) range from $9.1 million to $30.6 million.[427] With MVP 5 in service, the annual net benefits of MVP 3 alone (relative to the 161 kV Rebuild Alternative) range from $8.6 million to $22.7 million.[428] 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.[429] The benefits of "the project," which is essentially one-half of MVP three accrue at these amounts only with the other half of MVP 3 modeled, plus the addition of MVP 4 and/or MVP 5.

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 and Route Permit 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/CN-12-1053 ET-6675/TL-12-1337

CITIZENS ENERGY TASK FORCE AND NO CAPX 2020

AFFIDAVIT OF CAROL A. OVERLAND

STATE OF MINNESOTA)
) ss.
COUNTY OF GOODHUE)

Carol A. Overland, after duly affirming, states and deposes as follows:

1. My name is Carol A. Overland, an attorney licensed in good standing in the State of Minnesota, and I represent Citizens Energy Task Force and No CapX 2020, limited intervenors in the above-captioned docket.

2. Documents referred to in pre-filed testimony and other documents necessary to inform the record are not included in the application and/or testimony, and should be included to inform the record. This was raised at the Fairmont public hearing:

   MS. LISA AGRIMONTI: Your Honor, I would suggest that if Ms. Overland knows which document she would like to have in the record that she has until May 30th to provide that information.

   MS. CAROL OVERLAND: Gladly.

   Transcript, p. 142, l. 16-20, Fairmont Public Hearing. Attached I am providing, under oath, relevant industry documents to inform the record.

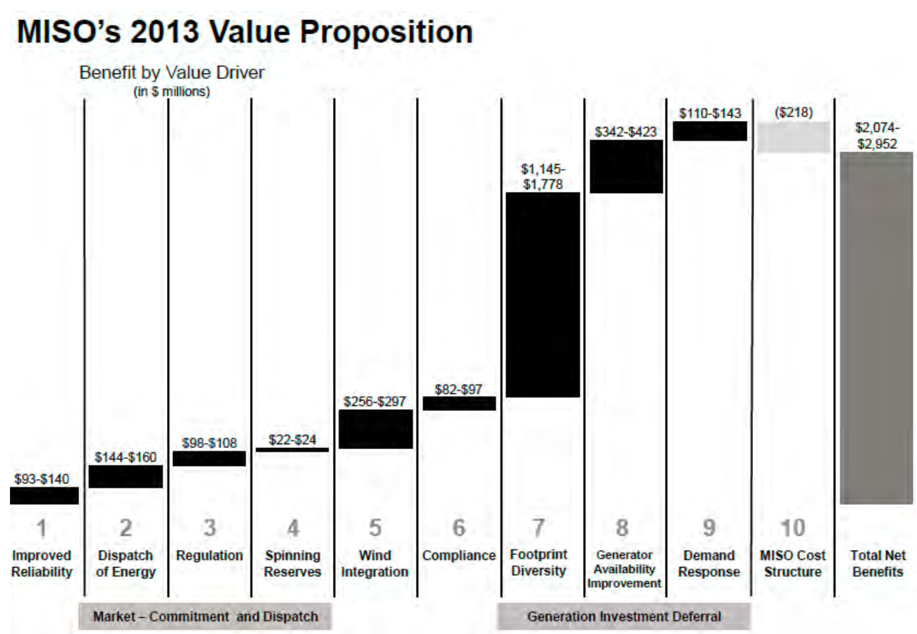
3. Attached as Exhibit A is a true and correct copy of MISO Tariff MM, setting out cost apportionment calculations for MISO filings for rate recovery.

4. Attached as Exhibit B is a true and correct copy of MISO Schedule 26A dated 2/26/2014, regarding total cost of various MVP projects, cost apportionment, and expected costs by balancing authority, i.e., NSP, or ATC. ITC is not a "balancing authority."

5. Attached as Exhibit C is a true and correct copy of MISO's Value Proposition Study dated February 2014. As stated on slide 3:

> **The 2013 Value Proposition study shows that MISO provides between $2.1 and $3.0 billion in annual economic benefits to its region**
>
> **What is the MISO Value Proposition?**
>
> The Value Proposition study is a quantification of value provided by MISO to the region including the entire set of MISO market participants and their customers
>
> This value is provided through improved grid reliability and increased efficiencies in the use of generation resources enabled by MISO market operations

6. The Value Proposition Study shows "Footprint Diversity" and "Generator Availability Improvement" as the primary drivers, meaning that transmission expansion expands the footprint of deliverability, and the transmission expansion improves generator availability by making generation accessible to distant markets.



7

7. What we see in that chart is that the MISO "Cost Structure" takes away, in the best case scenario, $218 million, or over one-half of the "benefits" of Generator Availability Improvement at $342-423 million, or most of the "benefits" of wind integration at $256-297 million, or the lion's share of "Improve reliability" and "Dispatch of Energy" at $237-300 million.

8. Attached as Exhibit D is a true and correct copy of the ICF Independent Assessment of MISO Operational Benefits dated February 2007, which explains the "use of generation resources enabled by MISO market operation" as coal generation, supported by Exhibit C, the MISO Value Proposition Study, above, and concluded:

> *The overall outcome of this analysis demonstrates that potential RTO benefits are large and are measured in hundreds of millions of dollars per year. While on a percentage basis the potential improvement appears modest, the magnitude of the production costs involved is so large that on a dollar basis, the efficiency improvements are substantial.*
>
> ***RTO operational benefits are largely associated with the improved ability to displace gas generation with coal generation, more efficient use of coal generation,*** *and better use of import potential. These benefits will likely grow over time as:*
>
> > *• Reliance on natural gas generation within the Midwest ISO footprint grows as a result of the ongoing load growth and a general lack of non gas-fired development over the last 20 years. This may increase the scope for potential savings from centralized dispatch in future years.*
> >
> > *• Tightening environmental controls and the resulting greater diversity in coal plant fleet variable operating costs will make optimization of coal plant utilization more important in future years.*
> >
> > *• Tightening supply margins throughout the Eastern Interconnect over the next three to five years increase the importance of optimizing interchange with neighbors such as PJM, SPP, and others.*
> >
> > *• Transmission upgrades which could increase the geographic scope of optimization within the Midwest ISO footprint.*

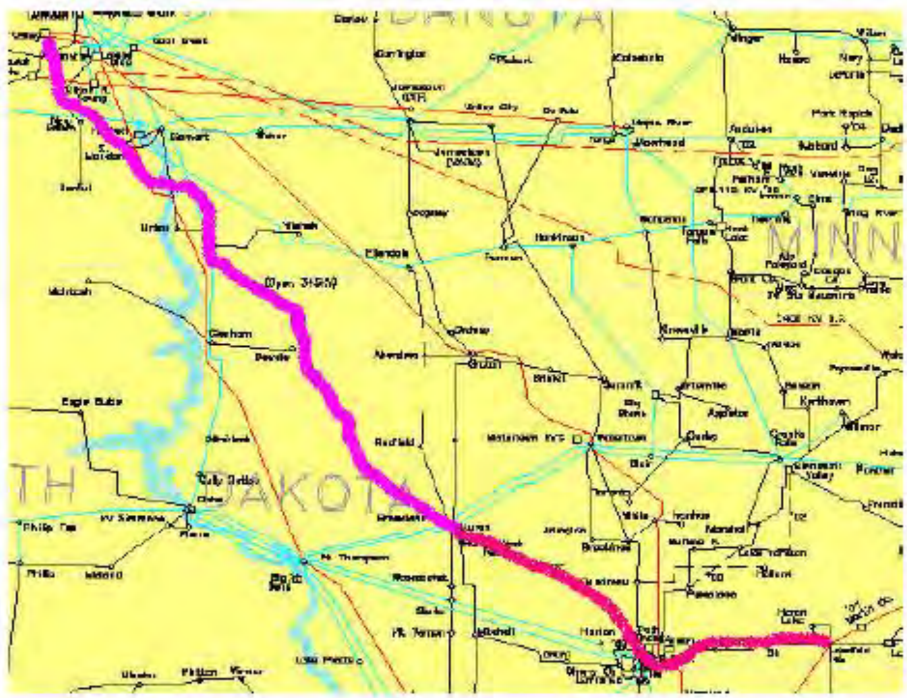
Ex. D, p. 14, 83, ICF Independent Assessment of MISO Operational Benefits (**emphasis added**).

9. Transmission expansion for generation outlet has long been planned in this area of the Midwest. Attached as Exhibit E is a true and correct copy of the ABB Lignite Vision 21 transmission development and marketing plan and Phase II Transmission System Impact Study Summary Report, dated February and November, 2001, "to assist in the development of additional lignite-based electrical generation in North Dakota," to "increase North Dakota export."

> *Initially studies were made for identifying the common facilities required to export 2,450 MW from North Dakota with the new Lignite Vision 21 500-MW power plant. Studies were also made for identifying the facilities required to export 2,800 MW from North Dakota with the new Lignite*

Vision 21 500-MW power plant plus an additional 350 MW in transmission reservations.

A common factor is the "70-mile, 345 kV circuit between Split Rock and Lakefield Junction," now permitted and constructed, to which this ITC Midwest project will connect (CoN PUC Docket 01-1958). The Split Rock – Lakefield Junction line is shown on the lower right portion of this map, the relatively-horizontal magenta line:



10. David Grover, Manager for Regulatory Strategy for ITC Holdings, parent company of ITC Midwest, has long been involved in transmission build-out planning, including NSP's TRANSLink (PUC Dockets 02-2152; 02-2219), Wisconsin Advance Plan, and as co-facilitator of the WIREs Study. Attached as Exhibit F is a true and correct copy of the WIREs Phase II study showing a 1999 transmission planning study of options to provide transmission capacity into Wisconsin, including the "9b" option from Lakefield Junction, Minnesota to Columbia (Madison), Wisconsin.

> Three new reinforcement plans were developed based on the options evaluated in the Phase I process. Plan 9b (Lakefield Jnc – Adams – Genoa – Columbia 345 kV) is a trimmed version of the Phase I Option 9a and is less costly from a construction cost standpoint. Plan 5b (Apple River – Weston 230 kV) was added to consider dynamic and voltage stability performance of a lower voltage version of Plan 5a. Plan 10 (King – Weston 345 kV) was added because of the potential dynamic stability differences between it and Plan 5a (Chisago – Weston 345 kV). The group discussed the King – Weston reinforcement in the Phase I process but noted that from a thermal standpoint, it is electrically similar to Plan 5a. However, potential dynamic and voltage stability differences prompted the group to add Plan 10 to the Phase II process.

"Plan B" essentially runs a 345 kV transmission line from Lakefield Junction to Columbia, Wisconsin, which is accomplished in a more round-about way with MVP 3, MVP 4 and MVP 5.

11. History of transmission is particularly important in this location in Minnesota. The "Clean Energy Intervenors" have executed at least two agreements related to this project, the "Merger Agreement" with a material term regarding "825 MW" of transmission and "removal of impediments to transmission," and the TRANSLink Agreement, paving the way for "transmission only" companies and the transmission build-out. Both were entered into the record of the respective PUC Dockets. Attached as Exhibit G is a true and correct copy of the 1999 Merger Agreement. Attached as Exhibit H is a true and correct copy of the TRANSLink Settlement Agreement (PUC Dockets 02-2152 and 02-2219). It is not established in the record whether David Grove, ITC, formerly NSP and working on TRANSLink, was involved in this TRANSLink Settlement Agreement.

12. On September 8, 2001, Beth Soholt, Izaak Walton League (then its Wind on the Wires program) and Matt Schuerger, ME3 (now Fresh Energy) held a meeting with 7 or 8 likely intervenors[1] in the Split Rock – Lakefield Jct. 345 kV transmission proceeding (PUC Docket 01-1958). This ITC Midwest MN/IA transmission project connects to that project at Lakefield Junction. During the September 8 discussion, I pointed out the future coal generation in the SW MN/SE SD study, and they would not address the potential for use of the line for coal generation outlet, i.e. the new MidAmerican 700 MW coal plant.[2] We were directly asked by Beth Soholt, "What would it take for you to approve of this line?" I asked, "What's in it for us," and got no substantive response. I then asked, "What are you getting for your agreement," and I again got no substantive response. I did not "approve" of this transmission line, and was not offered, nor did I receive any enticement or incentive to approve of it, or any other transmission line.

13. I later learned that there was a lot in it for them in approving of transmission – for example, there were two significant "Wind on the Wires" grants regarding transmission advocacy, $4.5 million in 2001 and $8.1 million in 2003. Attached as Exhibit I are true and correct copies of announcement of the McKnight Foundation/Energy Foundation "Wind on the Wires" grants totaling $12.6 million, $4.5 million in 2001 and $8.1 million in 2003. The "collaboration" of environmental groups in the administrative and legislative venues was essential to permitting of CapX 2020. Attached as Exhibit J is a true and correct copy of 2005 Session Laws Ch. 97. Attached as Exhibit K is a true and correct copy of the June 17, 2008 Testimony of William Kaul., Great River Energy.

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[1] Myself, Bill Neuman, Kristen Eide-Tollefson, Sigurd Anderson, George Crocker, Dan Juhl, Jack Keers and perhaps others.

[2] P. 21, Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission Outlet Analysis for Southwest Minnesota, Draft #1, August 17, 2001. See p. 29-30, November 13, 2001 version -- online at www.oatioasis.com/woa/docs/NSP/NSPdocs/Outlet_rpt_2.doc

14. There have also been significant RE-AMP transmission advocacy grants to the intervening organizations appearing in this docket.[3] Attached as Exhibit L is a true and correct copy of a RE-AMP funding list. RE-AMP continues beyond that in Exhibit K, funding transmission advocacy by Clean Up Our River Environment, Montevideo, MN, and Center for Rural Affairs, of Lyon, NE. CURE's Duane Ninneman[4] and Lucas Nelson of CFRA[5] attended the DEIS meeting in Jackson, but did not make any statement. Mr. Ninneman attended the Blue Earth Public Hearing, and did not make any statement.

15. On or about February 17, 2014, I spoke with Keven Reuther, MCEA, who stated that MCEA, Wind on the Wires, Izaak Walton League, and Fresh Energy were intervening in support of the ITC Midwest MN/IA and the Xcel/ATC Badger Coulee transmission lines.

16. Attached as Exhibit M is a true and correct copy of the "Regional Transmission System Reinforcement Options" map found on p. 8 of the Wisconsin Reliability Assessment Organization (WRAO) Report, showing the option of a 345 kV line from Lakefield Junction to the Madison area. This is electrically similar to the ITC/MidAmerican MVP 3, when combined with existing infrastructure and the necessary MVP 4 and MVP 5.

17. Attached as Exhibit N is a true and correct copy of the March 6, 2006, DOE Comment of Wind on the Wires and others, proposing as a NEITC transmission corridors in Minnesota and Iowa that is substantially similar to ITC/MidAmerican MVP 3 and MVP 4, and another similar to the CapX Brookings (MVP 1) and Fargo projects:

18. Commerce's Dr. Steven Rakow changed his testimony on the eve of the evidentiary hearing, ostensibly based on "new facts" regarding the Odell Wind Farm heard during the statement of Aaron Backman, E.D., Economic Development Authority, City of Windom.

[3] Midwestern RE-AMP groups are leading the national participation of nongovernmental organizations in a stakeholder process to plan and build economic models of the transmission system needed for clean energy generation. http://reamp.org/content/uploads/2014/01/RE-AMP_overview_2011-1.pdf

[4] RE-AMP position of Ninneman http://www.cureriver.org/2014/01/07/cure-senior-director-assumes-clean-energy-responsibilities/

[5] CFRA on RE-AMP Steering Committee http://www.cfra.org/about/staff/brian-depew

Dr. Rakow testified that he did not know whether Mr. Backman was under oath, testified that he was at the first day of public hearings, and also testified that he did not hear any others testify about the Odell Wind Farm. However, two others did comment that day about the Odell Wind Farm – at the public hearing in Blue Earth, Geronimo's Justin Pickar spoke about Odell on behalf of Geronimo, and also in Jackson, Geronimo's Jason Burmeister spoke about Odell on behalf of Geronimo. Aaron Backman was not under oath for his statement at the Jackson public hearing. Neither Justin Pickar and Jason Burmeister were under oath. No members of the public who spoke were offered the option of testifying under oath.

19. Prior to the start of the public hearing I requested that all witnesses be given the option of testifying under oath. That request was denied. I requested that this denial be put on the record. That request was denied. Minnesota Rules regarding conduct of hearing address testimony under oath. For example, all evidentiary testimony presented to prove or disprove a fact at issue shall be under oath or affirmation. Minn. R. 1400.7800, Subp. G; see also Minn. R. 1400.7200 (All oral testimony at the hearing shall be under oath or affirmation.). The Ch. 1405 PPSA Rules are more specific and discount the weight of testimony based on whether it was offered without the benefit of oath or affirmation:

1405.0800 PUBLIC PARTICIPATION.

> At all hearings conducted pursuant to parts 1405.0200 to 1405.2800, all persons will be allowed and encouraged to participate without the necessity of intervening as parties. Such participation shall include, but not be limited to:
>
> A. Offering direct testimony with or without benefit of oath or affirmation and without the necessity of prefiling as required by part 1405.1900.
> B. Offering direct testimony or other material in written form at or following the hearing. However, testimony which is offered without benefit of oath or affirmation, or written testimony which is not subject to cross-examination, shall be given such weight as the administrative law judge deems appropriate.

20. Dr. Rakow states that the information presented by Backman is "new facts." However, this testimony was not under oath and therefore not proof of any "facts". Further, it is not "new" because the MISO Queue shows that the Odell Wind Farm, G826, has been in the MISO queue since July 16, 2007.[6] The Feasibility Study Report was issued 9/30/2008 and the link is posted on the MISO Queue.[7] The System Impact Study Report was issued and the link is posted on the MISO Queue.[8] This report was dated Marcy 29, 2013, and was entered into the record as Exhibit 535. The Odell Wind Project Power Purchase Agreement is PUC Docket E-002/M-13-603. The site permit is PUC Docket 13-843, owned by Geronimo, and Christine Brusven is Gerinomo's attorney of record. In addition, Geronimo's attorney Christine Brusven was present at the ITC Midwest MN/IA DEIS meetings and was also present at the Public and Hearings. Upon information and belief, Ms. Brusven also working on land acquisition matters for this ITC Midwest

[6] MISO Queue online: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=18896
[7] G826 Feasibility Study link: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=16051
[8] G826 System Impact Study link: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=23730

project. Below is a true and correct image taken by me, that's Christine Brusven in front of the red tractor at this Jackson meeting location:

20. Both ITC Midwest and Geronimo had counsel present, staff present, and had numerous opportunities to enter information and/or present testimony on the record, under oath, but they did not. There was no opportunity to cross-examine any witness regarding the Odell Wind Farm under oath.

Further your affiant sayeth naught.

May 30, 2014

Carol A Overland

Carol A. Overland #254617
Attorney for CETF and NoCapX
Legalectric
1110 West Avenue
Red Wing, MN 55066
(612) 227-8638
overland@legalectric.org

Signed and affirmed before me this
30th day of May, 2014.

Leah M. Dietz

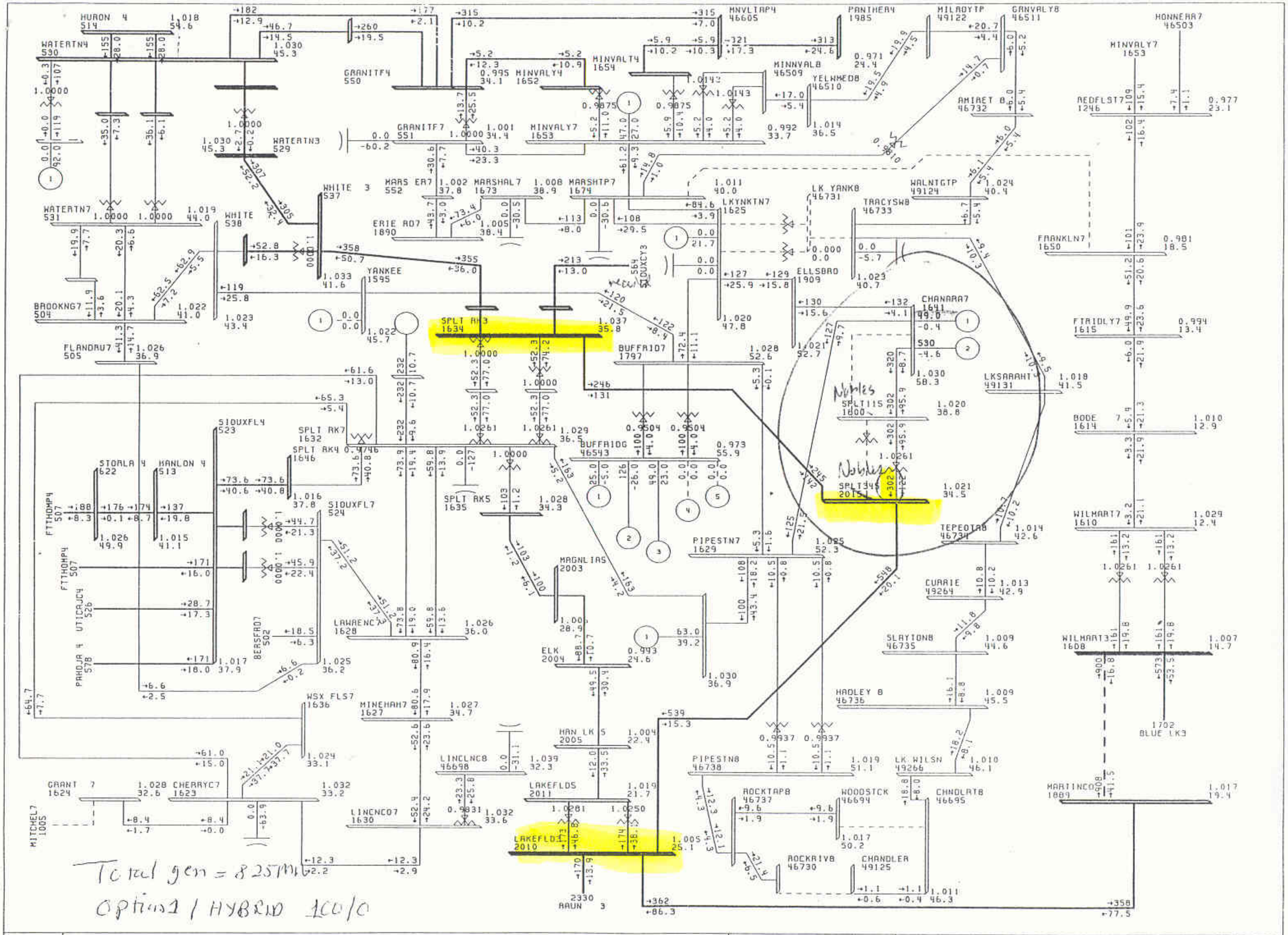
Notary Public

LEAH M. DIETZ
Notary Public-Minnesota
My Commission Expires Jan 31, 2015

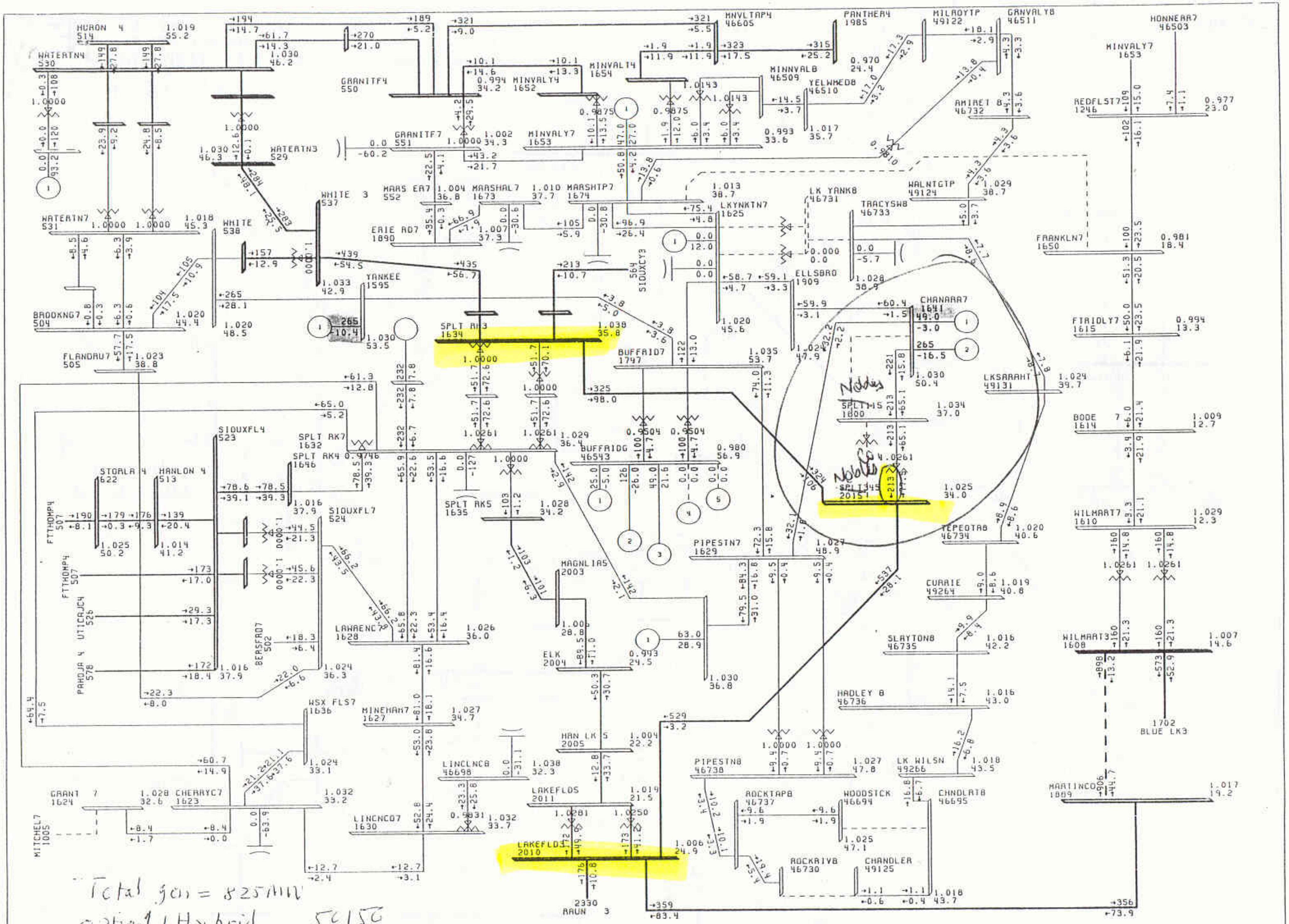
Powerflows from PUC Docket 01-1958

100/0 and 50/50

Explained in testimony of Rick Gonzalez



POWER TECHNOLOGIES, INC.®	OPTION1-CHB-S001.SAV; DANUBE TO TROY OPEN; SPK-LAJ; L ND=1949, MH=2150, MN=1069; BRI-WHITE LINE. 100% AT CHB CHA2-345.DRW WED, MAY 22 2002 14:14	100% RATEA 0.920UV 1.100OV KV: ≤115 , ≤161 , ≤230	BUS - VOLTAGE (PU)/ANGLE BRANCH - MW/MVAR EQUIPMENT - MW/MVAR



Total gen = 825 MW

option 1 / Hybrid 50/50

OPTION1-YANKEE-BUFFALORIDGE.SAV;DANUBE TO TROY OPEN
ND=1949,MH=2150,MN=1069;0 % AT CHB;50 % AT YANKEE
CHA2-345.DRW WED, MAY 22 2002 14:06

POWER TECHNOLOGIES, INC.®

100% RATEA
0.920UV 1.100OV
KV: ≤115 , ≤161 , ≤230

BUS - VOLTAGE (PU) / ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

Xcel Energy 58

FY 1 [illegible]

2nd packet
b

Option 1H "50/50"
Option 1 + Buffalo Ridge-Yankee-White 115 kV

Add Split Rk-Lakefield Jct 345 kV
Add 345/115 kV intermediate sub & 115 kV line north to Chanarambie
Add Buffalo Ridge-Yankee-White 115 kV
Add Troy 69 kV SS
Chanarambie-Lk Yankton-Lyon Co 115 in
Willmar-Paynesville 230 in
50% incr gen @ Chanarambie, 50% @ Yankee

Incremental MW, w/r to 425 MW base	300 MW base		Facility overload			Applicable Rating, MVA	Outage	Remedy	Qty	Cost	Installed Cost, $1000 Incremental	Cumulative
-1475	-1350	C	Wilmarth	Martin Co	345	631	Sherco #3 gen trip	Upgrade to 100 deg C	1 ea	1,000 ea	1,000	1,000
-860	-735	C	Lakefield	Fox Lk	161	240	Martin Co-Wilmarth 345	Build 2nd LAJ-Fox Lk ckt	24 mi	220 /mi	5,280	6,280
-860	-735	C						Line terms @ LAJ & Fox Lk	2 ea	800 ea	1,600	7,880
-645	-520	C	Minn Valley 230/115 kV tx (100 MVA)			115	Granite Falls-Minn Valley 230	Replace with 187 MVA	1 ea	1,500 ea	1,500	9,380
-580	-455	C	Summit	Dome	115	154	Blue Lk-Wilmarth 345	Reconductor	2.8 mi	95 /mi	266	9,646
-570	-445	C	Willmar 115/69 tx			65.8	Granite Falls-Willmar 230	Replace with 112 MVA	1 ea	1,200 ea	1,200	10,846
-380	-255	C	Alexandria	Douglas Co	115	105	Inman-Wing River 230	Reconductor	11 mi	95 /mi	1,045	11,891
-350	-225	C	Dome	Loon Tp	115	152	Blue Lk-Wilmarth 345	Reconductor	22.1 mi	95 /mi	2,100	13,991
-125	0		Fox Lk	Rutland	161	250	Martin Co-Wilmarth 345	Rebuild	18 mi	220 /mi	3,960	17,951
-125	0										0	17,951
-120	5							Add CHB-LAY-LYC 115 kV	1 ea	48,000 ea	48,000	65,951
-110	15	C	Paynesville	Wakefield	115	124	GF-MinnValley-Panther 230	Reconductor	15.0 mi	95 /mi	1,425	67,376
-95	30	C	Elbow Lk	Grant Co	115	105	Fergus Fls-Henning 230	Reconductor	3.6 mi	95 /mi	342	67,718
-5	120	C	Willmar	Kerkhoven	115	84	Granite Falls-Willmar 230	Reconductor	14.7 mi	95 /mi	1,397	69,114
0	125										0	69,114
5	130							(base plan)	1 ea	69,250 ea	69,250	138,364
55	180		Rutland	Winnebago	161	250	Martin Co-Wilmarth 345	Rebuild	16 mi	220 /mi	3,520	141,884
115	240	C	Brandon	Elbow Lk	115	105	Fergus Fls-Henning 230	Reconductor	16.6 mi	95 /mi	1,577	143,461
180	305	C	Paynesville 230/115 tx			215	GF-MinnValley-Panther 230	Increase to 336 MVA	1 ea	500 ea	500	143,961
220	345		Minn Valley	Redwood Fls Tp	115	153	Minn Valley-Panther 230	Reconductor	27.7 mi	95 /mi	2,632	146,593
250	375										0	146,593
265	390										0	146,593
265	390		Pipestone	Pathfinder	115	247	Nobles Co-Chanarambie 115	Add BRI -Yankee-White 115	26 mi	250 /mi	6,500	153,093
265	390							BRI ring bus & new line term	1 ea	2,200 ea	2,200	155,293
265	390							White line term	1 ea	800 ea	800	156,093
270	395	X	Brookings	White	115	160	White 345/115 tx	Add 2nd 345/115 tx	1 ea	3,000 ea	3,000	159,093
275	400	C	Black Dog 230/115 tx			187	(System intact)	Replace with 336 MVA	1 ea	1,500 ea	1,500	160,593
340	465		Paynesville	Roscoe Tp	69	52.8	Paynesville-Wakefield 115	Rebuild as dbl ckt 115/69	7.6 mi	300 /mi	2,280	162,873
360	485	X	Douglas Co	Long Prairie	115	80	Inman-Wing River 230	Reconductor	19.3 mi	95 /mi	1,834	164,706
390	515		Redwood Fls Tp	Franklin	115	153	Minn Valley-Panther 230	Reconductor	13 mi	95 /mi	1,235	165,941
395	520		Roscoe Tp	Munson Tp	69	52.8	Paynesville-Wakefield 115	Rebuild as dbl ckt 115/69	4.0 mi	300 /mi	1,200	167,141
400	525											167,141
415	540	C	Brandon	Alex SS	115	106	Fergus Fls-Henning 230	Reconductor	13.2 mi	95 /mi	1,254	168,395
420	545	X	White 345/115 tx			250	Brookings-White 115 kV	(added 2nd tx @ 270 MW)	0 ea	0 ea	0	168,395
420	545		Fergus Fls	Hoot Lk	115	105	Fergus Fls-Wahpeton 230	Reconductor	2.1 mi	95 /mi	200	168,595
450	575		Loon Tp	W Faribault	115	152	Blue Lk-Wilmarth 345	Reconductor	10.6 mi	95 /mi	1,007	169,602
455	580		Farm Tp	Munson Tp	69	52.8	Paynesville-Wakefield 115	Rebuild as dbl ckt 115/69	2.0 mi	300 /mi	600	170,202

495	620		Granite Falls	Minn Val Tp	230	418	Martin Co-Wilmarth 345	Reconductor	2.5 mi	95 /mi	238	170,439
505	630		Minn Valley	Panther	230	427	Martin Co-Wilmarth 345	Reconductor	30.3 mi	95 /mi	2,879	173,318
550	675		Lk Yankton	Buffalo Ridge	115	292	White-Yankee 115	Reconductor	20.0 mi	95 /mi	1,900	175,218
585	710		Maple River	Wahpeton	230	220	Hankson-Wahpeton 230	Upgrade line term	1.0 ea	200 ea	200	175,418
635	760	X	White	Yankee	115	459	Nobles Co-Fenton 115	Build 2nd line to Fenton	14.0 mi	200 /mi	2,800	178,218
635	760							Line terms @ Nobles & Fenti	2 ea	800 ea	1,600	179,818
635	760	X	White	Yankee	115	459	Nobles Co 345/115 tx	Add 2nd 345/115 tx	1 ea	2,500 ea	2,500	182,318
650	775											182,318
680	805		Dome	Loon Tp (undergrnd)	115	220	Blue Lk-Wilmarth 345	Reconductor Underground	1.0 ea	550 ea	550	182,868
705	830		Pipestone	Pathfinder	115	225	White-Yankee 115	Reconductor	42.3 mi	95 /mi	4,019	186,886
705	830							Line terms @ Yankee & Whi	2 ea	800 ea	1,600	188,486
710	835		White	Yankee	115	459	Split Rk-Pathfinder 115	Build 2nd SPK-PAF 115	1.0 ea	2,600 ea	2,600	191,086
755	880		Pipestone	Buffalo Ridge	115	292	White-Yankee 115	Build 2nd White-Yankee 115	6.0 mi	200 /mi	1,200	192,286
795	920											192,286
840	965		Brookings	Flandreau	115	132	Split Rk-White 345	Reconductor	28.1 mi	95 /mi	2,670	194,956

Base Plan

345 kV line (Split Rk-Nobles Co-Lakefield Jct)	94 mi	450 /mi	42,300
115 kV single ckt Nobles Co-Chanarambie	24 mi	200 /mi	4,800
Split Rk sub: line term & 50 MVAR 13.8 kV reactor)	1 ea	2,000	2,000
Lakefield Jct sub: line term	1 ea	1,500	1,500
Nobles Co 345/115 kV sub, 40 MVAR cap & 50 MVAR reactor	1 ea	9,000	9,000
115 kV line term @ Chanarambie	1 ea	800	800
Troy 69 kV Switching Station	1 ea	3,000	3,000
Ft Calhoun-Omaha interface upgrade	13 mi	450	5,850
Total for base plan			69,250

R Gonzalez
5/19/2002

Schatzki Rebuttal Schedule 2

Pages 8-9, 12-15

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

	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
		MISO Production Cost per MWh Load ($/MWh)			MISO Production Cost per MWh Change			
		[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

	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
		MISO Production Cost per MWh Load ($/MWh)			MISO Production Cost per MWh Change			
		[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

	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	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 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.