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March 28, 2025

Will Seuffert
Executive Secretary
Public Utilities Commission
121 – 7th Place East, #350
St. Paul, MN 55101

eFiled and email: consumer.puc@state.mn.us

RE: "NEED" Initial Comment
The Prehn Family & NoCapX 2020
Mankato-Mississippi Transmission Line f/k/a Wilmarth-N Rochester-Tremval
PUC Certificate of Need Docket CN-22-532

Dear Mr. Seuffert:

Thank you for the opportunity to file this Comment, made on behalf of the Prehn Family and NoCapX 2020. The Prehn Family has been a participant in utility issues for over 60 years, beginning with the licensing of the then Minnegasco gas dome in the 1960s which was taken up to the Minnesota Supreme Court; to stopping Minnegasco's pollution of local fields by obtaining an EAW and construction of a water treatment system; to stopping the proposed Simon natural gas plant next to the Minnegasco pumping station along Hwy. 13; and now this transmission project through southern Minnesota.

I. INITIAL NEED COMMENTS

The record must reflect that this project initially proposed a route to run right over the gas dome, without prior notification to CenterPoint, and it was the Prehns who notified CenterPoint of this route proposal on April 25, 2024, and Xcel did not meet with CenterPoint until May 1, 2024,[1] and subsequently withdrew the route over the gas dome:

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[1] 20245-206448-02 NORTHERN STATES POWER COMPANY, DOING BUSINESS AS XCEL ENERGY SUPPLEMENTAL 05/06/2024

> *Segment 1 Alternative 1L*
> In Segment 1 of the project, the applicant identified several routing alternatives (referred to as 1A through 1M), including 1L. The applicant has had additional discussions with CenterPoint Energy regarding existing infrastructure and future planned expansions of infrastructure as it relates to Segment 1 Alternative 1L. The proposed 345 KV transmission line would require setbacks from existing gas wells to allow for CenterPoint Energy to access the gas wells with large operational and maintenance equipment, and additional setbacks would be necessary to allow for planned equipment additions and expansion of the CenterPoint Energy Waterville Gas Storage Facility. The applicant has determined that Segment 1 Alternative 1L is no longer a feasible route alternative due to the necessary setbacks from CenterPoint Energy's existing and planned facilities.[12] The applicant requested that Segment Alternative 1L be removed from consideration as a routing alternative for the project.[13] Segment 1 Alternative 1L will not be analyzed in the EIS.

EERA Scoping Decision, p. 4 of 8, November 16, 2024. But for the Prehn's interests and actions, would Segment 1 Alternative 1L over the gas dome have been even noticed, much less eliminated?

Similarly, NoCapX 2020 has intervened in multiple transmission dockets since 2006, pushing 20 years, and the issues remain much the same – so much so that utility forecasts from the CapX 2020 Certificate of Need proceeding[2] should be considered, particularly the "need" forecasts, as discussed below.

Bottom line: Claims of transmission need is misinformation at best. The issue in transmission is that transmission is not where it is wanted. There's sufficient generation, and that generation has been sited away from load where there is not sufficient transmission to interconnect, and sited where projects are waiting years and years to interconnect. The siting of all this generation far from transmission, far from load, and the following claim that transmission is "needed," falls on the applicants and on the Public Utilities Commission for permitting these projects. This is a systemic problem. It is unreasonable to require ratepayers and landowners to pay for this transmission, and doubly unfair when the proposed transmission is not to serve Minnesotans, but to enable MISO's marketing plan.

For years, decades really, this writer has been representing intervenors raising the essential truth that need is not a matter of utility and industry desires; that it is the distribution system that needs beefing up and that utilities are proffering transmission "solutions" to distribution deficiencies; and more recently, that MISO "approval" is not a demonstration of need – MISO is a marketing entity, and "benefits" of transmission it proposes are benefits to MISO members.[3] Most importantly in terms of this and other Certificate of Need dockets, the Commission abdicates its responsibility to ratepayers and the public when it accepts a MISO approval as need, rather than give the project a robust Minnesota oriented independent review, and instead permits billions in utility marketing desire and subsequent transmission costs that are foisted on ratepayers and landowners.

This "North Mankato – North Rochester – Tremval" project does not exist in a vacuum. As

[2] PUC Docket CN-06-1115.
[3] See e.g., Attachment A, Testimony of George C. Loehr in the PATH docket, addressing the issues present in this and all other utilities' MISO Tranche 1 and 2 transmission applications.

declared in the application, it is project 4 of MISO $10 billion Tranche 1:[4] And although the project is a part of the MISO Tranche 1, the Minnesota Public Utilities Commission is MINNESOTA'S regulator and must address the "need," the benefits and impacts to Minnesota.

ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

[4] MTEP21 Addendum-LRTP Tranche 1 Report with Executive Summary, p. 2 https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf

A. THE COMMISSION TOO FREELY AUTHORIZES "EXEMPTIONS" FROM PROVISION OF INFORMATION CRUCIAL TO A NEED DETERMINATION

An overarching concern regarding Certificate of Need dockets is that applicants are routinely exempted from many of the application requirements for a Certificate of Need. As Xcel noted in its Exemption Request:

> The Commission has authority to grant exemptions from the requirements of Minnesota Rules Chapter 7849 pursuant to Minn. Rule 7849.0200, subp. 6.

Xcel Exemption Request, p. 4[5]. Xcel requested the following Exemptions:

Minnesota Rule	Scope of Exemption
Minn. Rule 7849.0260, subps. A(3) and C(6) (Losses)	Request exemption from providing line-specific loss information. Xcel Energy proposes to provide substitute data in the form of overall system losses.
Minn. Rule 7849.0270, subps. (1) through (6) (Forecasting)	Request exemption from providing specific forecasting and capacity information. Xcel Energy proposes to provide substitute forecast information used in analyzing the need for the Project.
Minn. Rule 7849.0270, subp. 2(E) (Annual Revenue Requirements)	Request exemption from providing annual revenue requirements for the Project. Xcel Energy proposes to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.
Minn. Rule 7849.0280, subps. (B) through (I) (System Capacity)	Request full exemption from providing a discussion of the ability of the existing system to meet the forecasted demand for electrical energy identified in response to Minn. Rule 7849.0270.
Minn. Rule 7849.0290 (Conservation)	Request exemption from discussing conservation programs and their effect on the forecast information required by Minn. Rule 7849.0270. Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.
Minn. Rule 7849.0300 (Consequences of Delay); Minn. Rule 7849.0340 (No Facility Alternative)	Request to be exempt from providing analysis using three confidence levels. Xcel Energy proposes to provide substitute data regarding potential impacts caused by delay or by not building the Project.

Id., p. 5-6.

Just because something is authorized, just because it has been done that way before, does not mean that it should be done! More likely, it's an indication that scrutiny is needed.

Xcel leads its Exemption Request using MISO review and approval as its basis for the request:

> *The Project was studied, reviewed, and approved as part of the Long Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent*

[5] 202310-199659-02 22-532 (CN) XCEL ENERGY Initial Filing EXEMPTION REQUEST AND ATTACHMENT A 10/17/2023

Independent System Operator, Inc.'s (MISO Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report. The Joint Utilities filed a notice of intent to construct, own, and maintain the Project with the Commission on October 10, 2022.

The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as a portion of LRTP4 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio. The transmission system in southern Minnesota is the nexus between significant renewable resources in Minnesota and the Dakotas and the regional load center of the Twin Cities and load centers to the east in Wisconsin. The amount of renewable energy generation on the electric system is increasing as aging traditional generation resources retire and are replaced with renewable resources. This Project will provide additional transmission capacity that is needed to reliably deliver this renewable energy to customers. This Project will relieve overloads on existing transmission facilities and will also reduce congestion on the transmission system resulting in lower energy costs.

Id., p. 3 (footnotes omitted).

Xcel claims that "[b]ased on the standard set forth in this rule, the Commission may grant exemptions when the data requirements: (1) are unnecessary to determine need in a specific case; or (2) can be satisfied by submitting documents other than those required by the rules," but check the chart above for what it is they are using:

- Xcel Energy proposes to provide substitute data in the form of overall system losses.
- Xcel Energy proposes to provide substitute forecast information used in analyzing the need for the Project.
- Xcel Energy proposes to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.
- Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.
- Xcel Energy proposes to provide substitute data regarding potential impacts caused by delay or by not building the Project.

At this time, the Commission and other detractors will say that this is not the time for addressing Exemptions, that it's water under the bridge. However, as a part of its need review, it's the job of Commission, and Commerce DER, to determine whether what is actually produced by Xcel is sufficient, whether the information requested is in fact unnecessary to determine need in a specific case; or whether the information required in the rule can be satisfied by submitting documents other than those required by the rule. A part of that review should be careful examination of those matters targeted for exemption to determine whether they are material matters for consideration.

While the Commission has exempted Xcel from providing this data for this project, it is exemptions only to its rules for **application content**. Xcel is not exempted from providing that data in the process of review of its application, if consideration of that data is warranted. A cursory look says these exempted categories deserve a closer look. For example:

1. **Xcel Energy proposes to provide substitute data in the form of overall system losses.**

Xcel Energy's first item on its list for exemption is line loss. That's a presumed indicator of the level of importance to Xcel. System-wide losses have become the standard since the SW Minnesota 345kV transmission docket, 01-1958, which turned on line losses, hence that information is no longer disclosed.

The Commission knows that transmission entails significant losses, as disclosed in the MN Energy CON transmission line docket (CN-22-131 and TL-22-132). In that docket, Xcel admitted that that of 2,200 MW generation into the line, it would deliver only "approximately 1,996 MW to the Sherco Substation." The Commission clearly stated this in its Order, that the Commission presumes "approximately" 204 MW line loss, if 160 miles, 12.75%, and if 180 miles, 11.33% is lost[6]. At long last the Commission is recognizing, in an Order, the inherent inefficiencies of transmission over distance. Going forward, in its need determination, such as this Mankato-Mississippi transmission docket, the Commission must require disclosure of line loss for this project over the distance from Mankato to the Mississippi River (if considering just Minnesota), and weighing in its need determination the impacts of line loss and the amount of additional generation, reactive power or other voltage stabilizing methods, necessary to make up for that line loss. Line loss is an inherent inefficiency of transmission, it's the laws of physics, and despite the grand rush and effort to permit more transmission, there is no excuse to ignore line loss.

But that's exactly what Commerce DER recommended, that Xcel not even disclose the specific "Mankato-Mississippi" line loss, based on Xcel's statement and prior exemptions granted by the Commission, with no support, relying only on Xcel's statement. This DER recommendation was accepted by the Commission and Xcel was exempted from providing line loss attributable to this specific project, as was required for the MN Energy CON line. The Commission had actual

[6] In the Commission's Order of August 10, 2023 (CN-22-131; TL-22-132), the commission admitted, after interconnection of 2,200 MW, line losses of approximately 204MW, to result in 1,996 delivered to the Sherco substation, roughly a MW per mile, as did Xcel in describing the specs of the line -- from the application:

> The two lines would be located on the same set of structures (i.e., a double-circuited transmission line) and would connect at least 2,200 megawatts (MW) of generation and deliver (after losses) approximately 1,996 MW to the Sherco Substation.

knowledge of the high percentage of line loss on that line, and this Mankato – Mississippi is even longer. Though Xcel was exempted from disclosing line loss in its application, it has not been exempted from disclosure of line loss information in the Certificate of Need proceeding.

What was disclosed in the application? An example of expected line loss is found in "LRZ1" without and with LTRP4, the Mankato-Mississippi project plus the Wisconsin portion (mindful that MVAR losses must be compensated for in some manner, i.e., injection of reactive power and/or series compensation, etc.):

Table 4-15
Estimated Line Losses

MTEP22 2027 Shoulder High Wind Line Losses for LRZ1						
Model	**Base Model**	**LRTP 4**	**Delta**	**Tranche 1 without LRTP 4**	**Tranche 1**	**Delta**
MW Losses	1031.8	999.8	32.0	883.4	849.4	34.0
MVAR Losses	9628.6	9513.5	115.1	8882.3	8770.1	112.2

Future 1 Year 20 Shoulder High Wind Line Losses for LRZ1						
Model	**Base Model**	**LRTP 4**	**Delta**	**Tranche 1 without LRTP 4**	**Tranche 1**	**Delta**
MW Losses	1220.5	1159.6	60.9	1071.0	1027.0	44.0
MVAR Losses	10834.4	10490.2	344.2	9941.9	9782.6	159.3

Table 4-16
Average Line Losses

	Average SH Losses
MW Losses	42.73
MVAR Losses	182.70

Xcel Application, p. 82.

First, look at those charts – looking strictly at MW losses, is consideration of line loss make any sense when the plan for this project is to spend $457.4 million dollars (MISO) to $577.2 million dollars (Xcel) for a claimed loss savings of 32-34, 44, or 60.9 MW, averaging 42.73MW? That's over $10 million per megawatt! Is that loss savings any justification for this project? Then take a look at the full losses admitted – the LRZ1 MW and MVAR losses are roughly the equivalent of the 2 reactor Prairie Island Nuclear Generating Plant's capacity. In addition, what will this need for support cost in terms of reactive power, series compensation, and the generation needed to make up for these line losses? Note that only LRTP4 is in the chart, and no "Mankato-Mississippi" transmission project, so we have no idea losses attributable to this project.

The cost of line loss and reactive power specifically related to this line must be considered and weighed in determination of need for this Mankato-Mississippi portion of this project.

2. **Xcel Energy proposes to provide substitute forecast information used in analyzing the need for the Project.**

What forecast information does Xcel plan to use? A simple search of the application for the word "forecast" shows that Xcel is relying on MISO. From the Table of Contents:

- **4.2.4 MISO Futures Development and Transmission Planning**
- **4.2.5 LRTP Tranche 1 Portfolio**
- **4.2.6 MISO's Summary of Need for the Project**

See Xcel Application, pps. 53-62. Then the application goes on to state "Xcel's analysis" of forecast:

> First, Xcel Energy conducted an analysis based on the most current MISO transmission system model (MTEP22) assuming no additional generation is added to the system. …
>
> Second, Xcel Energy conducted an analysis based on the MTEP21 Future 1 (at year 20) to show improvements to system reliability related to the Project in the future when additional generation is online.

Xcel Application, p. 67. Xcel's "analysis" focused on MISO territory of Zones 1 and 2:

Map 4-4
MISO Local Resource Zones

Id., p. 69.

When a Minnesota utility bases its Certificate of Need case before the Minnesota Public Utilities Commission on MISO forecasts, MISO futures and MISO regions 1 and 2, and the "Xcel analysis" is also fully based on MISO, it's clear the driver is MISO, a marketing entity, which includes Xcel. It's also shown in Xcel's own application that this is not about Minnesota. What's in it for Minnesota?

The estimation of "benefits" and drafting of the entire plan are MISO's doing, logically utility driven. Thus far, the benefit is the MISO members (see below, MISO LRPG Tranche 1 Benefits Chart, Figure 4.4). There's no demonstrated benefit to Minnesota, its ratepayers, and the landowners whose land will be taken for this project, yet isn't the Commission's responsibility protection of Minnesota, its ratepayers, and landowners through regulation of utilities?

a. Xcel's demand is NOT increasing

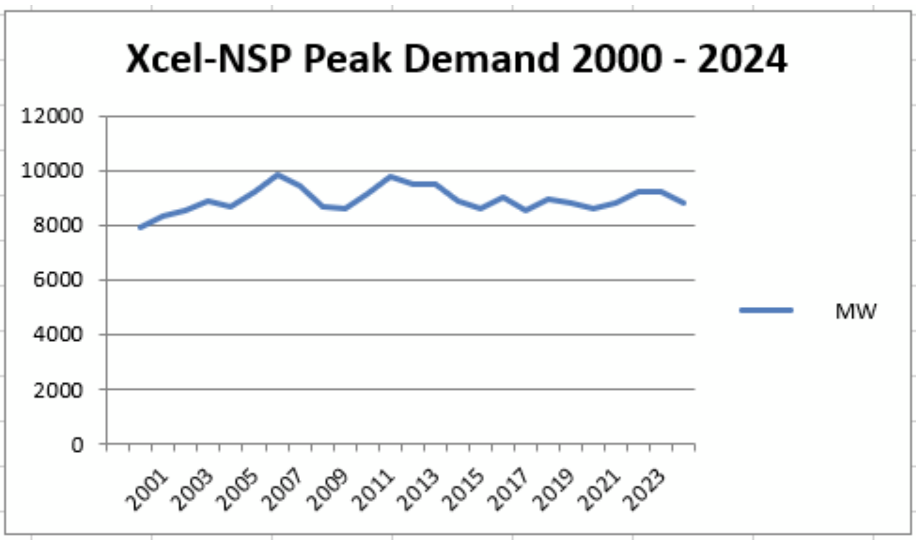
On the other hand, Xcel's reliance on MISO makes sense, because where "need" is concerned, Xcel has a "need" problem because Xcel's demand has not yet met the 2006 peak of 9,859MW, calling "need" into question. From Xcel Energy's SEC 10-K filing[7], the peak of 2024:

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

	2024		2023	
Utility Subsidiary	**MW**	**Date**	**MW**	**Date**
NSP System	8,822	Aug. 26	9,231	Aug. 23
PSCo	7,084	Aug. 1	6,909	July 24
SPS	4,437	Aug. 19	4,372	Aug. 17

This is important because at 8,822 MW, Xcel's peak demand is down 409 MW from last year. More importantly, at 8,822 MW, Xcel's peak demand has not reached the all-time high peak demand of 9,859 MW in 2006! Why is this important? Xcel is now crying that "demand will go UP, UP, UP!" as it falsely claimed in the CapX 2005. What does Peak Demand look like over the last 25 years according to Xcel Energy's SEC 10-K filings? Here are the numbers:



From Xcel's 10-K SEC filings:

2000	7,936
2001	8,344
2002	8,529
2003	8,868
2004	8,665

[7] Xcel's 2024 SEC 10-K: https://legalectric.org/f/2025/02/Xcel-Peak-Demand-2024_0000072903-25-000029-e2853810-9fe1-4df5-89d1-e14f11e5c841.pdf

2005	9,212
2006	9,859
2007	9,477
2008	8,657
2009	8,615
2010	9,131
2011	9,792
2012	9,475
2013	9,524
2014	8,848
2015	8,621
2016	9,002
2017	8,546
2018	8,927
2019	8,774
2020	8,571
2021	8,857
2022	9,245
2023	9,231
2024	8,822

Xcel has met its need each year, and peak demand has been below the 2006 high, **in 2024, 1,000MW lower**, despite forecasted CapX 2020 "forecast" of 2.49% annual growth.[8]

b. System line losses in MW and MVAR are greater than Xcel's peak demand

In this transmission application, Xcel includes tables regarding line loss. Xcel's 2006 peak demand of 9,859MW… that 9,000MW number seems familiar… oh, right, it's that chart of line losses, and MVAR losses of over 9,000MW in the system as it is, it's even more than Xcel's peak demand!

Table 4-15

Estimated Line Losses

MTEP22 2027 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 4	Delta	Tranche 1 without LRTP 4	Tranche 1	Delta
MW Losses	1031.8	999.8	32.0	883.4	849.4	34.0
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Future 1 Year 20 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 4	Delta	Tranche 1 without LRTP 4	Tranche 1	Delta
MW Losses	1220.5	1159.6	60.9	1071.0	1027.0	44.0
MVAR Losses	10834.4	10490.2	344.2	9941.9	9782.6	159.3

One of the tropes of transmission build-out is that more transmission, and these high capacity transmission lines, would lower line loss! Apparently not!

[8] See CapX 2020 Technical Update, p. 5 (2005), Attachment E to CapX 2020 Certificate of Need Application. https://nocapx2020.info/wp-content/uploads/2012/02/capxvisionstudy20120214-515026913743.pdf

c. Xcel's forecasts are historically grossly overstated

There's another reason Xcel would rely on MISO and wouldn't want to make its own case for need. Not all of us have forgotten Xcel's very gross overstatement of need in the CapX 2020 need docket, with the preposterous forecast claim of a 2.49% annual increase! Xcel has a habit of overestimating demand, as noted by the Office of the Attorney General in a recent docket.[9] From the PUC's 2021 IRP Order, DER-Commerce also recognizes that overstatement of demand:

> The Department presented its own proposal that differed from Xcel's in many respects. In particular, the Department argued that over time Xcel's analysis systematically overestimates demand and underestimates capital costs, leading the company to propose needlessly expansive growth.

Order, p. 11, PUC Docket RP-19-368.

As we saw in the CapX 2020 need docket (CN-06-1115), Xcel "systematically overestimates demand and underestimates costs." In 2006, if you recall, or if you'll do homework, as many of you were not around then, Xcel was saying, as the basis for its CapX 2020 transmission expansion, that demand would go UP, UP, UP at an astronomical rate of 2.49% ANNUALLY!.

Control area	2009 load level (2004 MAPP Series) (MW)	Yearly growth rate (%)	Calculated 2020 load level (MW)
ALT (West)	3265.3	1.60	3888.2
Xcel Energy (North)	9632.6	2.68	12885.1
MP	1507.3	1.70	1814.4
SMMPA/RPU	330.0	2.70	442.4
GRE	2833.5	3.27	3943.2
OTP/MPC	1677.2	2.70	2248.3
DPC	954.7	2.60	1266.2
Total	20200.6	Ave. = 2.49%	26487.8

Table 1 – CapX 2020 Anticipated Area Growth

> Table 1 shows an anticipated load growth of approximately 6300 megawatts (MW) in the CapX 2020 region for the period from 2009 to 2020. The technical team also studied historical loads for Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, and Xcel Energy to determine whether anticipated load growth was consistent with historical load growth in the region. Load growth for these companies averaged 2.64 percent during the period 1980 to 2004. Diagram 2 shows the variability of load growth as well as the continuing upward growth in load for the region. The technical team's forecast from 2009 through 2020 is a slower growth curve than the actual growth in the early 2000's (2.49 percent vs. 2.64 percent).

From the CapX 2020 Vision Study, p. 5[10]:

Really. What a load! This forecast was not credible then, and now with so much verifiable data

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[9] Attachment C, OAG-RUD, Comments p. 16, Xcel IRP Docket 24-67 202412-212710-03 (Dec. 4, 2024), citing 2022 IRP Order at 11; Docket No. E-002/RP-19-368, Supplemental Comments of the Department of Commerce at 9 (Oct. 15, 2021).

[10] https://nocapx2020.info/wp-content/uploads/2012/02/capxvisionstudy20120214-515026913743.pdf

from Xcel's own SEC filings, there's no excuse. Yet buying into that notion, the Commission granted a Certificate of Need[11] for the CapX 2020 transmission projects. Xcel and its "environmental" proponents claimed then and now that increased generation and transmission is "needed" for renewable energy, and Xcel states:

> The amount of renewable energy generation on the electric system is increasing as aging traditional generation resources retire and are replaced with renewable resources. This Project will provide additional transmission capacity that is needed to reliably deliver this renewable energy to customers.

Exemption Request, p . 4. Xcel admits that there is increased renewable energy generation, and admits that "traditional generation resources retire and are replaced with renewable resources." "Replacement theory" doesn't work politically, and it makes even less sense in physics. For transmission, when you remove generation, that frees up transmission capacity. There's no logical need for more, and there certainly is no need for a MISO Tranche 1.The existing system handled the peak in 2006, and since that time massive amounts of transmission capacity have been added via CapX 2020 and MOSI's MVP projects, particularly in southern Minnesota with the SW MN 345kV transmission project (PUC 01-1958); CapX 2020's Brookings-Hampton and Hampton-La Crosse – Cardinal Sub (Madison); and ITC's MVP Projects 3, 4 and 5, across southern Minnesota, northern Iowa, and off towards Madison. Add to this transmission capacity the capacity resulting from closing of coal plants. With all this transmission capacity, what's the real issue? Name that gorilla in the room.

If transmission isn't where they "need" it (want it), if Xcel and renewable developers are siting new generation in the wrong places, if the Commission is permitting projects where there is not sufficient transmission capacity for the generation, this is a problem of Xcel's, the developers', and the Commission's creation. Why should, why would, the Minnesota Public Utilities Commission buy into this and make ratepayers and landowners take the hit?

3. Xcel Energy proposes to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.

By proposing to provide "general information regarding how the costs for LRTP projects are shared within the MISO footprint," Xcel is diverting from cost of this project to Minnesota, which logically includes Minnesota ratepayers and landowners.

Xcel has yet to disclose how this specific project's costs are apportioned in Minnesota, and will only discuss "how the costs for LRTP projects are shared within the MISO footprint." This raises that classic questions: Who benefits? Who pays?

Who pays? Look at MISO's Tranche 1 Schedule 26A.[12]

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[11] PUC Docket CN-06-1115

[1212] LRTP Tranche 1 Appendix A-4 Schedule 26A Indicative https://cdn.misoenergy.org/LRTP%20Tranche%201%20Appendix%20A-4%20Schedule%2026A%20Indicative625788.xlsx

On the other hand, who benefits? The "who benefits" question is relatively easy to resolve – and the "who benefits" is a side of the need calculation that should be assessed. Check the MISO Tranche 1 page for the "business case."[13] The benefactors of MISO's plans are to the MISO members:

Figure 4-4
LRTP Tranche 1 Economic Benefits[48]

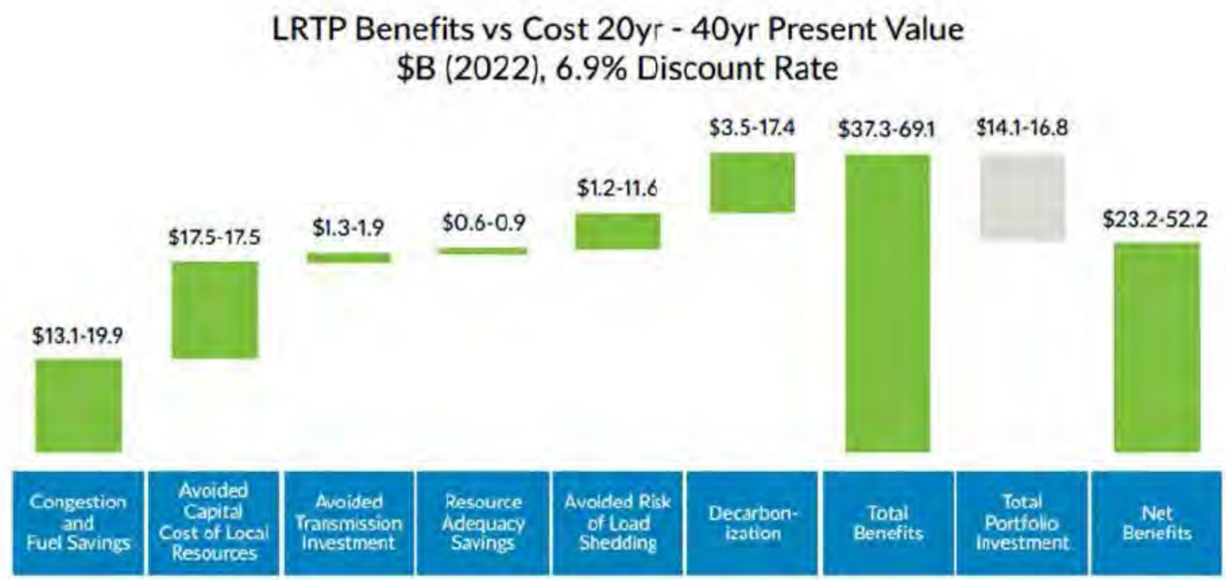


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

Who pays? That will be ratepayers via apportionment in various jurisdictions and landowners who lose their land to this project. Payment is not only for the infrastructure of the proposed transmission line, but also for the service that transmission line will provide.

For the entire MISO Tranche 1 "MISO projects that the MISO LRTP Tranche 1 Portfolio will provide $23.2 billion to $52.2 billion in net economic savings over the first 20 to 40 years (respectively) of the portfolio being inservice – a benefit to cost ratio range of 2.6 to 3.8."[14] Yet

[13] LRTP Tranche 1 Detailed Business Case
https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf
LRTP Tranche 1 Detailed Business Case Analysis
https://cdn.misoenergy.org/LRTP%20Tranche1%20Detailed%20Business%20Case%20Analysis625787.xlsx

[14] The footnote states, "The 2.6 to 3.8 benefit to cost ratio is for the entire MISO Midwest subregion. MISO projects that Minnesota and the surrounding region ("MISO Cost Allocation Zone 1") will realize a 2.8 to 4.0 benefit to cost ratio – slightly better than the broader MISO Midwest subregion." Note that the benefit cost is for the "entire MISO Midwest subregion," and the more geographically restrictive phrase above narrows it vaguely to "Minnesota and the surrounding region," with no boundaries, so it could meet anything.

look at, for example, the first three categories: Congestion and Fuel Savings, Avoided Capital Costs of Local Resources, and Avoided Transmission Investment. How many of those categories would be eliminated if generation was sited near load? Again, see Attachment A, Testimony of George C. Loehr. For MISO specific analysis of these "benefits" see Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics. MISO understandably finds the conclusions of this report objectionable – it points out the misinformation that serves as the basis for the MISO transmission build-outs, and the economic and reliability benefit of siting near load:

- It is important that this investment be economic –
  - ✓ Uneconomic investment will raise costs and undermine investment in resources, storage and other alternatives to transmission.
  - ✓ We have previously expressed concerns about the unrealistic nature of Future 2A growth assumptions.
  - ✓ MISO has chosen not to attempt manual optimization (evaluating alternative siting impacts on individual projects or to resolve overloads).
  - ✓ The benefits methodologies are likely to lead to substantially over-estimated benefits, which we describe in this presentation.
- MISO has proposed 9 classes of transmission benefits.
- Classes that are likely to be valid and reasonable, depending on the details:
  - ✓ Congestion and fuel costs savings
  - ✓ Reduced transmission outage costs
- Classes for which we have significant or fundamental concerns:
  - ✓ Avoided capacity costs
  - ✓ Decarbonization
  - ✓ Mitigation of reliability issues
- Classes that are may be overestimated depending on the methodology
  - ✓ Capacity savings from reduced losses
  - ✓ Energy savings from reduced losses
  - ✓ Avoided transmission investments
  - ✓ Reduced risks from extreme weather events

Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics.[15]

4. Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.

In Certificate of Need applications, the effect of conservation and energy efficiency are given

[15] Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics https://cdn.misoenergy.org/20240529%20LRTP%20Workshop%20Item%2002%20IMM%20Presentation633033.pdf

short shrift by the applicant and by the Commission. Here, Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.

In all analysis of conservation and energy efficiency, conservation and energy efficiency is least cost. Traditionally, conservation and energy efficiency are considered as "alternative" only where the conservation and energy efficiency" can replace, in toto, the claimed "need," and the combining of "alternatives" is deemed not to meet "need."

Before a need determination can be made, Xcel must demonstrate the possibilities that a combination of conservation and energy efficiency measures can produce, and proceed with a need claim on the balance, and only on the balance. See Minn. Stat. §216B.243, Subd. 3(7).

5. **Xcel Energy proposes to provide substitute data regarding potential impacts caused by delay or by not building the Project.**

The Exemption Request came before the Commission on the Consent Agenda, signed December 12, 2023.

1. Should the Commission grant the exemptions to the certificate of need application content requirements as requested by Xcel Energy in its filing on October 17, 2023?
2. Should the Commission approve Xcel Energy's Notice Plan Petition for a Certificate of Need for the Mankato - Mississippi 345 kV Transmission Project? (PUC: Panait; DOC: Miltich; Rakow)

The subsequent Order filed, dated December 12, 2023, addressed only approval of the Notice Plan, with nothing regarding the Exemption Request that had been on the Consent Agenda and approved, with a public Comment period, extended a week, ending on November 27, 2023. Xcel's proposed substitutions were approved with nominal, if any, consideration by the Commission, Commerce, and the public.

B. MISO IS NOT THE REGULATOR

Surprise – MISO IS NOT THE REGULATOR! The Commission and Department must be clear in its review that it is the regulator, not MISO, and assure that the Commission's review complies with Minnesota statutes and rules. Need more be said? I guess so, as the Commission gives great weight to MISO "approval."

However, on October 23, 2024, there was a Notice for Comments in this docket that admits that it's all about MISO:

Topic(s) Open for Comment:

- Should the Commission grant the exemptions to the certificate of need application content requirements as requested by Xcel Energy in its filing on October 17, 2023?

Background: Xcel Energy intends to file an application for a certificate of need with the Minnesota Public Utilities Commission for the construction of a single-circuit 345 kV transmission line in southeast Minnesota, designated as the Mankato – Mississippi Transmission Line Project. This project is part of the Long-Range Transmission Planning studied and reviewed by the Midcontinent Independent System Operator (MISO) and approved in July 2022.

Commission October 23, 2024 Notice for Comments.

Review and analysis of this Certificate of Need application must comply with Minnesota Certificate of Need statutes and rules. Minn. Stat. §216B.243, Subd. 3(7); Minn. R. ch. 7849.

C. COMMISSION SUBSTANTIVE CONSIDERATION OF NEED GOES BEYOND ACCEPTANCE OF APPLICANT'S STATED PURPOSE AND CLAIMED NEED

In earlier meetings in this docket, and it was stated in the Scoping Notice, the presentation (p. 27) and several times orally that at issue and up for comment is:

> **Are there other ways to meet the stated need for the project, for example, a different size project or a different type of facility?**

That statement means that the stated need/purpose as provided by an applicant is accepted and is the starting point for a need discussion. See Draft Scope, 1.0 "Purpose." This means that the purpose is accepted and that questioning that stated need and purpose is off the table.

NO! Acceptance of the "stated" need and purpose is abdication of the Public Utilities Commission's responsibility and mandate. **Size, type and timing of "need" is at issue** – that's why there is a Certificate of Need process and criteria in law (Minn. Stat. §216B.243, Subd. 3a (1-12)). This is a Certificate of Need docket (CN-22-532). The applicant and/or MISO are not the arbiters of need.

A need determination is to be made by the Commission after the review of factors, above, and a decision that is supported by facts and the record. A "stated need" by the applicant and/or a desire of MISO is not sufficient.

D. NEED AND SYSTEM ALTERNATIVES

The need analysis and system alternatives must address use of other voltage and configurations of transmission lines. The analysis must also include other system alternatives such as conservation and energy efficiency, siting near load, electrical system alternatives analyzed separately from the market desires of Xcel and MISOl

According to Xcel's application, page 162, the "System Peak Energy Demand" is 718 MVA. The project is designed for 3,585 MVA, Table 5-1. 3,585 MVA is roughly FIVE TIMES more than Xcel's highest claim of "System Peak Energy Demand" of 718. If "System Peak Energy Demand" is 718 MVA, according to Table 5.1, a single circuit 230kV line would be sufficient! See Draft Scope, 1.0 Design. The Commission must address this discrepancy and clearly evaluate Xcel's case for a line with capacity FIVE times higher, 3,585 MVA, than the "System Peak Energy Demand" of 718 MVA.[16]

E. **NEED IN A SYSTEM THAT'S "ALL CONNECTED" REQUIRES PUC CONSIDERATION OF EXISTING CAPX 2020, MVP 3, 4 &5, AND MISO TRANCHE 1, AND SPECIFICALLY THE FOUR TRANSMISSION LINES PROPOSED IN SOUTHERN MINNESOTA LESSEN NEED FOR NEW TRANSMISISON**

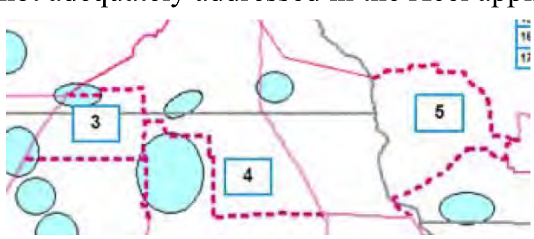
As testimony in the Arrowhead-Weston project declared 24 years ago regarding transmission, "it's all connected." This proposed Wilmarth-North Rochester-Tremval or Mankato, North Rochester, Mississippi Transmission Project (note, no transmission line ends in the Mississippi River) is not proposed in a vacuum. That it's all connected is a fundamental characteristic of "the grid." When considering "need," for a project, phased and connected actions must be considered.

This concept is important because, including this project, in addition to the recent transmission build-outs, there are FOUR transmission lines originating in southern Minnesota, and two of which go "against the current" of typical transmission power flows:

- Wilmarth-North Rochester-Tremval a/k/a Mankato-Mississippi (this docket)
- Brookings-Hampton 2nd circuit – CN-23-200 & TL-08-1474
- Big Stone-Alexandria-Big Oaks – CN-22-538 & TL-23-159/TL23-160
    - **Against the flow, SW to NE**
- MN Energy CONnection – CN-22-131 & TL-22-132
    - **Against the flow, SW to NE**

In light of all of these projects, and in light of existing transmission in southern Minnesota, is this project needed? The Public Utilities Commission must look to the big picture.

What's the big picture? Where is the "need" when considering the SW MN 345kV line (CN-01-1958) connecting into the MVP 3, 4 (TL-12-1337 and CN-12-1053), and the delayed but now fully permitted MVP 5, from SW Minnesota down into the top of Iowa and heading east into Wisconsin. Institutional memory, as MVP 3, 4 and 5's transmission in southern Minnesota and Iowa extending beyond are not adequately addressed in the Xcel application:



[16] See again Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics https://cdn.misoenergy.org/20240529%20LRTP%20Workshop%20Item%2002%20IMM%20Presentation633033.pdf

Consideration of these connected projects must also include consideration of the Public Utilities Commission's repeated actions of permitting projects where there is no interconnection option available. The Public Utilities Commission should not be permitting siting of generation based on wishful thinking and marketing plans. Those projects waiting for interconnection should be identified, and the Commission's actions declared void. If there is interconnection available, documented and at a cost outlined in the MISO DPP System Impact Study Reports, that cost should be properly allocated to the project developers and not Minnesota ratepayers.

F. LINE LOSSES HAVE IMPACT ON "NEED" FOR GENERATION AND ITS TRANSMISSION

Line losses have an impact on "need" for a project, because the longer the line, the higher the line loss, the more generation must be built to deliver a set amount of energy to its destination. The physics of long transmission lines is typically not considered, and must be. For example, as above in the "Exemptions" section, it's noted that the MN Energy CONnection transmission has declared an expected 200MW or more line loss, meaning that additional amount of generation must be built and paid for and land taken if the specific amount of energy is to be delivered, plus there's a reactive power requirement to stabilize the line, and also capital construction costs and transmission service cost that weighs against "need" for the project.

Typically, and improperly, the line loss for the project applied for is expressed as a percentage and/or megawatts across the entire MISO system or Eastern Interconnect. Line loss is an aspect of the project that should be reviewed separately for this project, terminal to terminal, for this particular project, and not hidden as a very small percentage or low MW of an undisclosed total energy across the system. Line loss is the amount of energy that would be dissipated by transmission over distance, and the amount and impact of the MW of additional generation to assure the requisite load gets to the other end of the line. The amount of increased generation necessary to make up for line loss will increase "need" for the project, so line loss must be compared between the project as applied for, and all alternatives presented, including the "no build" alternative.

G. ADDITIONAL TRANSMISSION NEEDED STARTING AT WILMARTH?

The Commission should consider why the starting point of the "North Mankato-Mississippi" line, f/k/a Wilmarth-North Rochester-Tremval" is proposed to start at the Wilmarth garbage burner or the North Mankato gas peaking plants. Does Xcel plan to renew the PPAs for those natural gas plants burning fossil fuel? Does Xcel plan to increase burning of garbage?[17] The Commission has recently been considering increased garbage burning and "biomass," which was previously decreased as a matter of policy limiting CO2 creation, because burning garbage creates CO2 output. Biomass was also disfavored due to dreadful economics. Biomass is not cost effective and generates CO2. The biomass mandate was legislatively removed from the 1994 Prairie Island legislation and Commission related statutes – there is precedent.

On the other hand, as a Red Wing resident, this writer noticed that Xcel's IRP 12 years ago

[17] See PUC Docket 23-151 and definition of "carbon free."

stated it would shutter the Wilmarth and Red Wing garbage burners.

> ***For capacity planning and RES compliance planning purposes, we are assuming that Red Wing and Wilmarth will be retired at the end of 2012.***

Attachment D, Xcel IRP, pages 6-7 to 6-8, PUC Docket RP-07-1572. Xcel apparently recanted on that assumption. Is there a plan to increase garbage incineration? If/when the Hennepin County HERC garbage burner is shut down, will that garbage burning be transferred to Wilmarth and/or Red Wing, increasing burning there? Is there a plan for increased generation in the immediate vicinity of Wilmarth? Where's the "need" for this project and why begin at Wilmarth/North Mankato?

H. NO-BUILD ALTERNATIVE

Among other things, the "no-build alternative" must be evaluated in the EIS because it may well not be needed in light of the several other projects planned for southern Minnesota. As detailed above, analysis of the "no-build alternative" must consider the now existing Split-Rock-Lakefield Jct. transmission line (01-1958); CapX 2020 Brookings-Hampton transmission including recent upgrade; CapX 2020 Hampton-La Crosse – Cardinal; and MISO's MVP 3, 4, and 5 across southern Minnesota, into Iowa, and then Wisconsin. The "new" Tranche 1 projects are, again:

- Wilmarth-North Rochester-Tremval a/k/a Mankato-Mississippi (this docket)
- Brookings-Hampton 2nd circuit upgrade – CN-23-200 & TL-08-1474
- Big Stone-Alexandria-Big Oaks – CN-22-538 & TL-23-159/TL23-160
- MN Energy CONnection – CN-22-131 & TL-22-132

I. SYSTEM AND ROUTE ALTERNATIVES OFFERED FOR CONSIDERATION

At the Pine Island hearing on July 9, 2024, Steve Hackman, of the North Route Group, offered specific system and route alternatives for the Chester 161kV line which should not only be reviewed in the EIS, but included in Certificate of Need potential system alternatives.

As a system alternative, a lower voltage option should be reviewed based on Xcel's claimed peak system demand MVA of 718, Application page 162, where proposed transmission is a gross overbuild.

No CapX 2020 and the Prehn Family offer these Initial Certificate of Need comments, and will be submitting Reply comments by April 25, 2025.

Very truly yours,

Carol A. Overland
Attorney for the Prehn Family and NoCapX 2020

OAH 65-2500-40099
MPUC E-022/CN-22-532
MPUC E-022/TL-23-157

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Xcel Energy for a Certificate of Need and Route Permit for the Mankato - Mississippi River 345 kV Transmission Line Project in Southeast Minnesota

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NOCAPX 2020 AND THE PREHN FAMILY

CERTIFICATE OF SERVICE

I, Carol A. Overland, hereby certify that I have this day served a true and correct copy of the attached Prehn Family and NoCapX 2020 Initial Comment to all persons at the email addresses on the Public Utilities Commission eDockets service list by eFiling and eService.

March 28, 2025

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TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George C. Loehr, and my business address is 4101 Killington Rd. NW, Albuquerque, NM 87114.

Q. BY WHOM ARE YOU EMPLOYED?

A. At present, I am self-employed.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Electrical Engineering degree from Manhattan College in 1962, and immediately began my engineering career with the Consolidated Edison Company of New York, working in bulk power transmission planning. I also pursued graduate studies at New York University, from which I received a Master of Arts in English Literature in 1964. Also in 1964, Con Edison enrolled me in the General Electric

Power Systems Engineering Course (PSEC) in Schenectady, NY, which I completed in 1965. Following the 1965 Northeast Blackout, I was actively involved in a wide range of follow-up activities. For example, I was Chairman of the Computer Committee, Federal Power Commission System Studies Group, Interconnected System. My committee completed an accurate computer simulation of the event – the first such successful simulation of a widespread power failure in North America. I was later named Division Engineer of Con Edison's Transmission Planning Division.

I joined the New York Power Authority (NYPA) as Chief Planning Engineer in 1969. Up until that time, all of NYPA's system planning had been by consultants, and my first assignment was to recruit and train a planning staff. I was responsible for management of the planning staff and the conduct of all NYPA bulk power system generation and transmission planning activities, which included load flow, transient stability, and loss of load expectation studies. I also served on many New York Power Pool and Northeast Power Coordinating Council committees and task forces.

I was hired by the Northeast Power Coordinating Council (NPCC) in 1972. Again, my first assignment was to recruit and train a technical staff. My major responsibilities were to manage the NPCC staff, which worked in support of the eight NPCC expert task forces, and to advise NPCC's Joint Coordinating Committees and Executive Committee. I became very active in regional, national and North American Electric Reliability Council (NERC) activities, and served on numerous committees, subcommittees and task forces. I also served on a Federal Power Commission advisory committee following the

1977 New York City Blackout. I was named Executive Director of NPCC in 1989, and remained in that position until my (early) retirement in 1997.

Since retiring from the NPCC, I have done management consulting, appeared as an expert witness, and taught a variety of courses on power systems – especially courses and workshops for non-technical professionals. My clients have included organizations throughout the U.S., Canada, and China.

At present, I am an Unaffiliated Member of the Executive Committee of the New York State Reliability Council (NYSRC), and currently serve as its Chair; I formerly chaired the NYSRC's Reliability Compliance Monitoring Subcommittee. In addition, I serve as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC), and as a member of its Audit Committee. I have served as Vice President and a member of the Board of Directors of the American Education Institute (AEI), and I was a charter member of Power Engineers Supporting Truth (PEST). I have given expert testimony in the states of Maine, Pennsylvania, New York, Vermont, Kentucky, New Mexico, Mississippi, and in Washington, DC. I have done TV interviews with BBC, CNN, WPIX and CBC, and have been a lecturer, keynote speaker, and/or chair at professional conferences in the U.S. and Canada. In addition, I've made audio tape lectures for various organizations, including the Institute of Electrical and Electronics Engineers (IEEE), Professional Development Options, Red Vector, and AEI. My articles have appeared widely in the trade press, including *Public Utilities Fortnightly, Electrical World, The Electricity Journal, Electricity Daily, Transmission &*

Distribution World, Energy Perspective, Restructuring Today, Energy Pulse, Natural Gas & Electricity, EnergyBiz, and the Belgian magazine, *Revue E tijdschrift*. I have been quoted in a number of U.S. newspapers, and interviewed on Michigan public radio. *The New York Times* published an op-ed piece of mine in 2006. I am co-editor of and a contributor to the IEEE book, *The Evolution of Electric Power Transmission Under Deregulation*.

In addition to my engineering career, I am a published author, have exhibited my art photographs at galleries in the New York metropolitan area, and have done stock photography for The Image Bank, a world-wide photo agency. My photos have appeared in numerous magazines, advertisements, business brochures, in several "coffee table" books, and as a book cover of a best seller. I recently published my own first novel, *Blackout*.

Q. PLEASE EXPLAIN THE MISSION OF THE NEW YORK STATE RELIABILITY COUNCIL (NYSRC).

A. The mission of the New York State Reliability Council is to promote and preserve the reliability of the New York State Power System in the New York Control Area. This mission includes developing, maintaining, and from time-to-time, updating the Reliability Rules which must be complied with by the New York Independent System Operator and all Market Participants. In fulfilling its mission, it works in close conjunction with the New York Independent System Operator. It carries out its mission in accordance with the New York State Reliability Council Agreement and the New York Independent System Operator/New York State Reliability Council Agreement.

Q. PLEASE EXPLAIN THE MISSION OF THE NORTHEAST POWER COORDINATING COUNCIL (NPCC).

A. The Northeast Power Coordinating Council (NPCC) was the first of the Regional Reliability Councils formed after the Northeast Blackout in 1965. Its role was (and is) to ensure the reliability of electric power systems in the northeastern United States and central and eastern Canada by developing, maintaining, and monitoring conformance with reliability criteria for planning and operations. It also provides a forum for the coordination of planning and operating procedures. NPCC's current membership encompasses New York State, the six New England states, and the Canadian provinces of Ontario, Quebec, New Brunswick, Nova Scotia, and Prince Edward Island. I might add that the main reason I left the New York Power Authority and joined NPCC was my keen interest in reliability and reliability criteria, and my wish to contribute toward making the bulk power system more reliable.

Q. PLEASE EXPLAIN THE ORGANIZATION KNOWN AS POWER ENGINEERS SUPPORTING TRUTH (PEST).

A. Following the August 14, 2003 blackout, several associates and myself, each with 40 years or more experience in electric power system planning and reliability, decided to form a group to bring out the truth about electric power system reliability. To this end, we established a not-for-profit organization, which we called Power Engineers Supporting Truth (PEST). As we stated in our *Principles*, which were issued in September 2003, our intent was "to identify the best ways to make the bulk power systems in the United States both more reliable and economic." We published several reports over the next few years, and made our reviews and recommendations available to the general public, as well as to interested industry groups, government officials, and the media.

Q. HAS THERE BEEN A COMMON THREAD TO YOUR TESTIMONY IN STATES SUCH AS MAINE, PENNSYLVANIA, NEW YORK, VERMONT, KENTUCKY, NEW MEXICO, AND MISSISSIPPI?

A. Yes. My expert testimony in the various states has focused on bulk power system reliability. So have my TV and radio interviews, my articles in the trade press, and my conversations with reporters and journalists.

Q. WHAT IS THE SUBJECT OF THE COURSES AND WORKSHOPS YOU NOW TEACH?

A. Virtually all of my courses and workshops, my speeches and lectures, and my audio tapes primarily address two subjects: how the interconnected bulk power system (or "grid") works, and the importance of keeping it reliable.

Q. HAS MOST OF YOUR CAREER FOCUSED ON ENSURING THE RELIABILITY OF BULK POWER SYSTEMS?

A. I would say that "bulk power system reliability" is the one concept that best characterizes my 47 year career. It is even the main subject of my recently published novel, *Blackout*.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY HERE?

A. I was asked by the Sierra Club to complete an independent evaluation of the PATH application and determine if the applicants had proven a reliability need for the line. I reviewed the PATH application, the testimony and exhibits submitted with the application, and numerous discovery responses and documents from the various parties.

Q. COULD YOU SUMMARIZE YOUR VIEWS?

A. A reliability need for the proposed 765kV line has not been clearly demonstrated. My major reservation is with the assumptions that underlie the contingency studies – especially the conditions assumed for the base case load flows upon which the contingency studies were run. More specifically:

- The applicants and PJM do not have *carte blanche* from NERC. While PJM has been designated by NERC as a Planning Authority (a.k.a. Planning

Coordinator since 2007) and Transmission Planner, it is not authorized to make whatever assumptions it wants when conducting planning studies. In my opinion, the assumptions and base conditions of the applicant's and PJM's studies are not credible and reasonable. Therefore, neither are the conclusions.

• PATH would not improve reliability. Rather, by making eastern load centers all the way from northern New Jersey to northern Virginia more dependent on remote generation and transmission lines hundreds of miles in length, PATH would *exacerbate* reliability.

• PATH would effectively provide a subsidy to existing and future western generators – access to the lucrative eastern load centers without cost to themselves. Conversely, the western subsidies would place eastern generators at a significant disadvantage. This is a clear violation of FERC's "fair and non-discriminatory" principle.

• PATH would encourage remote rather than local generation by providing western generators with free transmission access to eastern load centers. Existing coal-fired generators would be ramped up, and new coal-fired generators would be encouraged to site in the west.

• PATH's approval now, before commitments need to be made for generators and other resources, would be a strong incentive to increase the output of existing coal-fired plants, and for developers to build western generation. It would be a disincentive for developers to site future generation and other resources in the East, where they're most needed.

- PJM planning studies represent future generators which have executed only a Facilities Study Agreement (FSA) if they add to a reliability problem, but require the next step, an Interconnection Services Agreement (ISA), if they contribute to a solution. This is a clear case of bias, and violates FERC's "fair and non-discriminatory" principle. More important, it does not make engineering sense.

- The applicants seem focused almost exclusively on AC EHV transmission. Non-transmission alternatives, and even other transmission alternatives like HVDC, have been ignored.

- PJM's one-at-a-time planning is a piecemeal approach to solving reliability problems. PJM, as the RTO, needs to step up to the plate and start planning its system on a coordinated, integrated basis.

- In my view, the Load Deliverability procedure used by PJM comes up with Capacity Emergency Transfer Objective (CETO) values that are unnecessarily high, and seems out of synch with what the rest of the industry is doing. There are better, more systematic and technically consistent ways to determine the import capabilities required by Load Deliverability Areas (LDAs) to maintain reliability.

• Without PATH, the capability of the Mid-Atlantic LDA to import power would still be in excess of 6,000MW. In other words, with a 6,000MW transfer into the Mid-Atlantic area, there would be no reliability violations. Not one.

• In my opinion, NERC violations have not been established since the base case assumptions are too conservative. So, too, are the CETO/Load Deliverability procedures.

• PJM's procedure for establishing CETO values is far more conservative than other eastern ISO/RTOs. It's ultra-conservative when compared to New York and New England.

• In general, the PJM process for assessing reliability and determining "need" seems to favor extreme solutions – solutions far more massive than necessary. This overkill approach violates an important engineering principle: "Don't use a pile driver to hammer tacks."

• All of PJM's load deliverability testing, which it relied on in determining the need for PATH, was based on a single dispatch. NERC standards call for multiple dispatch scenarios: according to a NERC interpretation of Standards

TPL-002 and -003, "a variety of possible dispatches should be included in planning analyses."

• While NERC Planning Standards call for the system to be stressed, the interpretation of "stress" must be reasonable. PJM and the applicants take the concept of "stress" to unreasonable extremes.

• PATH isn't really about reliability – it's about economics. While western generators would earn greater profits, eastern load centers would become more dependent on long EHV transmission lines; thus major East Coast cities like Philadelphia, Baltimore, Washington and Richmond would become more vulnerable to interruptions and blackouts, either from natural phenomena or from terrorist attacks.

• The alleged "voltage stability" problems have not been proven. We've been shown "knee-of-the-curve" results from steady state load flows, but no actual time-domain stability results. The alleged voltage violations are also based on the unnecessarily high CETO values. At more realistic CETOs, there would be no violations.

• Other than construction of the 765kV PATH line, solutions to the alleged steady state voltage violations have not been addressed. Apparently, neither power factor improvements by adding capacitors at the distribution and subtransmission level, nor shunt capacitors at 115/138kV substations, have been considered.

- Despite the fact that the latest “re-tool” analyses show different violations occurring on lower voltage facilities in a time-frame further out in the future, no alternatives to PATH as originally proposed have been examined.

- Conclusions regarding reliability violations beyond the 2014 study year were based on extrapolated results. In my opinion, this is not an acceptable way to assess the reliability of plan the bulk power transmission system.

- The PATH “solution” is not consistent with the alleged need to improve reliability. To improve reliability, PJM needs to promote the location of generation and other resources close to the load centers, rather than build a transmission line which will provide an incentive for the construction of generation, probably coal-fired, hundreds of miles away.

- The *real* reliability problem in PJM is the present high dependence of the eastern load centers on remote generation and multiple EHV transmission lines, each hundreds of miles long. *This* is the problem PJM should be addressing; instead, PJM is pursuing policies which will make the problem worse.

Q. PLEASE EXPLAIN THE HISTORY AND BASIC CONCEPTS INVOLVED IN BULK POWER SYSTEM PLANNING AND RELIABILITY

A. Among the more important considerations when dealing with large power systems are the reliability standards or criteria used for planning and operations. These have been an integral part of the electric power industry since the very first systems were developed in the late 19th Century, but they became increasingly important as power systems expanded and merged to form what we now know as synchronous interconnections, or simply "grids."

Early "central station" systems were relatively simple. A major disturbance or "contingency" could, at worst, shut down electric service in a small area – e.g., one square mile. But the introduction of high voltage alternating current technology permitted the use of long lines at higher voltage. This led to power systems which spanned progressively larger areas. Also, systems found it advantageous to share generating reserves, and minimize reliability risks from transmission problems, by interconnecting with each other.

This process took place through most of the 20th Century until, by the early 1960s, power systems in most of the U.S. and Canada had coalesced into four large synchronous interconnections or "grids." The largest of these, the Eastern Interconnection, stretches from the Canadian Maritimes to Florida, and from the Atlantic Ocean roughly to eastern Montana, Wyoming, Colorado and New Mexico. It encompasses all eastern, central and prairie provinces of Canada except Quebec and Newfoundland. The Western Interconnection runs from the Rockies to the Pacific Coast, and includes the Canadian provinces of Alberta and British Columbia, as well as a small portion of the northern Baja in Mexico. The ERCOT Interconnection comprises approximately 75% of the state of Texas. Finally, the Quebec Interconnection consists of that province in its entirety.

Power system planning begins with today's system – electric system planners do not have the option of throwing away last year's (or last decade's) thinking and starting over from scratch. So the power system as it exists is the starting point. Along with that, planners must begin with today's system demand levels, and predict or "forecast" how customer actions will affect electric demand in the future. In the present "deregulated" or "restructured" electric power industry, the ownership of generating resources in many states is separate from the ownership of the bulk power transmission system. Generation is also competitive – various companies vie with one another in an open market.

There are two aspects to effective reliability: "resource adequacy," having enough generation and other resources to meet the customers' electrical demand; and "transmission reliability," the ability of the transmission system to deliver the power and withstand sudden contingencies without overloads, low voltages, instability, or loss of customer load. To meet these twin goals, power systems must establish certain standards for both planning and operations.

Resource adequacy (generation, DSM, etc.) is determined on a probabilistic basis. In most North America systems, the generally applied standard is "one day in ten years." This means that sufficient resources must be available to serve all firm customer demand on all but one day over a ten year period. Resource adequacy problems, or shortages in generating capacity and other resources, can lead to voltage reductions (or "brownouts"), public appeals, and rotating feeder outages. By their nature, they can usually be anticipated in advance, and actions taken ahead of time.

Transmission reliability is assessed on a deterministic basis. Transmission planning standards or criteria specify a variety of specific disturbances or "contingencies" – the bulk power system must be able to withstand any of these without adverse consequences. Failures of the transmission system can lead to overloads, cascading outages, instability, system separations – and total blackouts over widespread areas. They almost always occur without warning, and can rarely be anticipated; hence, preventive actions, other than scrupulous adherence to standards and criteria, generally are not possible.

Blackouts are usually caused by contingencies more severe than those specified in the applicable standards or criteria, by equipment failures, control system problems, human error, or some combination of these. They involve the break-up of the bulk power transmission system. Blackouts are not caused by shortages of generating capacity.

During the first half of the 20th Century, individual power systems each developed and applied their own planning criteria. By mid-century, however, with the dramatic growth of synchronous interconnections and the increasing use of the system to transmit power over long distances, the limitations of such an approach were becoming obvious. When the Northeast Blackout of 1965 occurred, it was plain to see that a more coordinated approach was necessary.

PJM, which had a much smaller footprint in 1965 than it has today, was already functioning with a uniform set of criteria. The systems involved in the 1965 blackout soon followed suit. Shortly after the blackout, they formed the Northeast Power Coordinating Council (NPCC). Other utilities across North America also formed their own regional reliability councils, which eventually encompassed most of the continent.

Each regional council established its own reliability criteria. Each also developed procedures for assessing conformance. Individual systems and power pools sometimes developed their own more detailed or more stringent criteria, but they were always responsible for adherence to the regional criteria as a minimum.

The regional reliability councils formed the National Electric Reliability Council (NERC) in 1968 to coordinate their activities nationally and develop overall reliability guidelines for their collective systems. NERC has evolved over the years. As additional Canadian systems became members, it became the North American Electric Reliability Council. But the most dramatic changes occurred in the wake of the August 14, 2003 Midwest/Middle Atlantic blackout. The Energy Policy Act of 2005 (EPAct) directed FERC to establish an Electric Reliability Organization (ERO). Its major role would be to develop and enforce mandatory reliability standards for planning and operations. After a period of study, FERC designated NERC as the ERO, and its name was changed to the North American Electric Reliability Council Inc.

Today, NERC develops reliability standards, which must be approved by FERC. The regional reliability councils may have their own criteria, but these must conform to NERC's. As provided by EPAct, compliance with NERC standards is mandatory. ISOs, RTOs and individual utilities, as well as all other market participants like generators and power marketers, are members of the regional reliability councils and must comply with both the regional criteria and NERC standards.

NERC planning standards require both short- and long-term studies. Any violations discovered in the short-term analyses must be addressed with appropriate solutions. On the other hand, the purpose of the long-term studies is to provide some indication of the nature and direction of future reliability problems, and to ensure that any recommended short-term solutions will be consistent with future needs.

Q. HOW ARE STANDARDS AND CRITERIA USED IN TRANSMISSION PLANNING?

A. The first step in evaluating the potential reliability need for new facilities is to investigate the existing transmission system for a chosen future year, with existing and planned generating resources added, along with any transmission additions already scheduled. First, power flow or "base load flow" cases are created, representing base conditions – generally, peak loads under various generation scenarios. Then, new load flow cases are run simulating a wide range of potential disturbances or contingencies. The results of these contingency load flows will indicate where and to what extent the existing system needs reinforcement. At this point, familiarity with the system and engineering judgment will usually suggest potential solutions to the violations, and typically several will be chosen for further scrutiny. The most successful enhancement will be chosen, consistent with a parallel cost-effectiveness analysis. Finally, non-transmission alternatives should also be identified and examined, and compared in terms of cost, reliability, and environmental impact with the preferred transmission solution.

One of the key questions is how severe the contingencies should be. Over the past fifty years, planning engineers have reached a consensus on what is commonly known as "worst single contingency" design – a.k.a. "n-1." This means that the system must be able to survive the worst single event which could happen to the bulk power system. Typically, this is the loss of a large generating unit, or a three-phase fault on a major transmission line or autotransformer. But the devil, as is said, is in the details.

Current NERC standards allow the planning entity a degree of judgment. NERC's TPL-002 and TPL-003, for example, require that the pre-disturbance system be *stressed*; however, the nature of the "stress" is not defined – despite several requests from transmission companies for a more definitive interpretation. It's up to the planning entity to fill in the details.

Specifically, NERC states in its February 8, 2005 interpretation of Standards TPL-002 and -003 that "a variety of possible dispatches should be included in planning analyses." NERC also specifies that the "selection of 'critical system conditions' and its associated generation dispatch falls within the purview of [the Planning Coordinator's] 'methodology.'" Finally, NERC directs that "a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios." One of the problems I have with the PJM approach is that only a single dispatch is used for all of the load deliverability analyses relied on in this proceeding.

Base conditions provide another example where the planning entity's judgment is required. This would include assumptions regarding appropriate load level, the handling of proposed new generation, the potential retirement or older generating units, and the dispatch of the overall system. Dispatch scenarios, which can be viewed as the bridge between "adequacy" (sufficiency of resources) and "operating reliability" (transmission reliability), are of particular interest. Generally, the best approach is to examine several different dispatch scenarios – varying the components and applying the most serious contingencies in each example.

Many planning entities today use a so-called "90/10" load forecast, as opposed to a "50/50" forecast, as one of many ways to satisfy the NERC "critical system conditions" requirement. This means that there is a 10% probability that the actual load will exceed the forecast demand, and a 90% probability that the actual peak demand will be lower.

In conducting planning studies, the critical contingencies as defined by the NERC standards are applied to the modeled system for each chosen scenario. Some of these contingencies will involve the sudden loss of a single element (n-1) – this could be a generating unit, critical transmission line, transformer, or any other power system component. Others contingencies will cause simultaneous loss of two related elements – such as both circuits of a double-circuit transmission line. Since the loss of both elements is caused by a single event, these are also referred to as n-1 contingencies. A few will involve the loss of two unrelated elements (n-1-1), with manual system adjustments between the two contingencies (usually within 10 minutes). Regardless of the contingency applied, the system must suffer no overloads, low voltages, cascading outages, instability, system separation or loss of firm customer load before adjustment.

Q. ARE THE RELIABILITY STANDARDS MANDATED BY NERC?

A. For some time, NERC has developed reliability standards for planning and operations. As a result of the Energy Policy Act of 2005 (EPAct), these are now mandatory under federal law. The NERC planning standards define the contingencies which the power system must be able to survive without significant adverse consequences – overloads, low voltages, instability, system separations, or blackouts. However, the NERC standards do *not* define the configuration of the system to which these contingencies are applied, other than to say that the system must be stressed – assumed base conditions must "cover critical system conditions and study years as deemed appropriate by the responsible entity." [NERC Standards TPL-002-0 and TPL-

003-0.] But the nature of the "critical system conditions" must be credible and reasonable.

NERC has designated various entities, including PJM, as Planning Authorities (Planning Coordinators) and Transmission Planners, as described in the NERC Functional Model. These are responsible for deciding how their systems will be configured – stressed – for application of the NERC contingencies. As NERC has stated, "The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority." [March 13, 2008 NERC Planning Committee interpretation of TPL-002-0 and TPL-003-0.] The language here (e.g. use of the word "credible") clearly indicates that the assumptions must have a basis in reality.

NERC does not scrutinize the manner in which the PJM or any planning entity's system is represented. Neither does FERC. NERC and FERC are not the drivers – the applicants and PJM are the drivers. And they must answer for the base system assumptions they have made.

In my opinion as an expert, the manner in which PJM and the applicants configured the PJM system prior to the application of contingencies went considerably beyond what I consider reasonable. If the base assumptions are not credible, then the contingency analyses based on them are not credible – even though the applied contingencies are those specified in the NERC standards. A house built on sand will not stand. The PATH studies are built on sand; they're based on assumptions, how the PJM system is represented, which are neither credible nor reasonable. Therefore, neither are the conclusions.

Q. BUT NERC HAS DESIGNATED PJM AS A PLANNING AUTHORITY AND TRANSMISSION PLANNER. DOESN'T THAT GIVE PJM AUTHORITY TO MAKE THESE DECISIONS?

A. Not completely – the assumptions must be credible and reasonable. NERC's designation of PJM and other entities as Planning Authorities and Transmission Planners does not give them *carte blanche* to make whatever assumptions they want when conducting reliability assessments and planning studies. NERC neither supports nor condemns PJM's decisions about base conditions – the PJM Load and Generation Deliverability procedure, for example. NERC doesn't endorse *any* planning entity's specific approach. Therefore, the applicants cannot hide behind PJM's designation as a Planning Authority and Transmission Planner to support the need for PATH.

Q. DO YOU BELIEVE THE PATH VIOLATIONS ARE REASONABLE?

A. No. The alleged violations are based on the applicants' initial assumptions, and in my view those are *not* reasonable. Why I believe that the procedures used in the PATH studies are not reasonable is covered in the remainder of my testimony. But the major objection I have is with what I consider an overly conservative process for determining the Capacity Emergency Transfer Objective (CETO), leading to an import target for the

LDA which is unnecessarily high. When the load flows are run to determine if there are any NERC violations, they use this import value; since it's unnecessarily high, finding "violations" is practically guaranteed. With a more reasonable import value, neither thermal nor voltage violations will be found.

Overall, PJM's and applicants' procedures are overly conservative. They pile conservative assumptions on top of conservative assumptions – beyond what, in my opinion, is reasonable. In brief, they push the "conservative" envelope too far.

Q. PLEASE COMMENT ON THE USE OF "CAPACITY EMERGENCY TRANSFER OBJECTIVE" BY PJM AND THE APPLICANTS.

A. For any defined Load Deliverability Area (LDA), PJM does a Loss of Load Expectation (LOLE) study to determine the import capability necessary to maintain a "one day in 25 years" LOLE. This is then called the Capacity Emergency Transfer Objective (CETO) for that LDA. The CETO value is based, among other things, on the load forecast. A mean or median schedule is developed for the LDA, using the same probabilistic statistics as in the LOLE, to accommodate an import equal to the CETO. Next, load flow cases are run at that value, simulating the various requirements of NERC Planning Standards TPL-001, -002, and -003. If the existing transmission system results in "violations" for any of these (A, B, and C), the planners conclude that a transmission reinforcement is required. PJM maintains that they're only permitted to consider transmission reinforcements.

In theory, the Capacity Emergency Transfer Objective (CETO) is the amount of import capability which the LDA geo-electric area would require to allow it to satisfy a chosen loss of load expectation, given its load characteristics and the amount of generation it contains.

Mr. McGlynn discusses the Mid-Atlantic LDA at some length in his testimony. He cites the Mid-Atlantic LDA's CETO used in PJM's April 2009 modeling as 8,190MW [McGlynn, page 28.]. In my opinion, the 8,000MW+ value he comes up with as the CETO is breathtakingly (and unnecessarily) high. That's an awful lot of power to transfer into eastern PJM from the West. It's a very large value to expect to export to *any* single area – something like one MW for every eight MWs of peak load. One has to ask if this is really a reliable way to supply a high percentage of the electric requirements of a metropolitan area that stretches from northern New Jersey to northern Virginia. That entire megalopolis would be subject to interruption by many and diverse causes, natural and human, intentional as well as unintentional. The present import capability of the Mid-Atlantic LDA is in excess of 6,000MW – a pretty high number itself. (Exhibit PFM3 lists the most restrictive contingency at a Mid-Atlantic LDA import of 6,240MW.) In other words, without PATH, it would still be possible to send more than of 6,000MW into eastern PJM. According to the PATH response to SierraVA-IV-61, there is 67,635MW of generating capacity in the Mid-Atlantic LDA as of October 2009 – *right now*. Given this amount of *existing* generating capacity, not even counting whatever additional capacity will be added over the next five years, why isn't a 6,000MW CETO enough? PJM should place greater emphasis on incenting new generation to locate within the Mid-Atlantic LDA, which would provide greater reliability to the eastern load centers.

In responding to the VAStaff-V-5 request for updated data on the Mid-Atlantic LDA, PJM cited a lower peak load forecast for 2014, an 827MW increase in installed capacity, and a lower CETO value – 7,720MW. This CETO reduction of 470MW further reduces any alleged "need" for the PATH line.

PJM's "one day in 25 years" standard – used to come up with the CETO number – is also questionable. This is a conservative assumption, PJM admits – part of the need to "stress" the system. To my knowledge, no other RTO or ISO uses a value this high. Why shouldn't PJM use "one day in 10 years," like everyone else? By comparison, one day in 25 years is a higher standard than that used by either ISO New England or the New York ISO, each of which is only about half the size of the Mid-Atlantic LDA. And this is on top of a 90/10 load representation, which would be expected to occur only once every ten years. PJM seems to pile one conservative assumption on top of another.

In fact, I would question whether a criterion of "one day in 10 years" for all of PJM is itself overly conservative, given the large size of the expanded PJM system. The New England and New York ISOs each use an adequacy criterion of one day in 10 years, yet each is approximately one-fourth the size (in MWs) of the PJM system. Standardized to the PJM peak load, New England and New York at one day in 10 years would be equivalent to *four* days in 10 years. New York and New England include metropolitan areas at least as critical as PJM's; why should PJM use a much more conservative reliability criterion? In my opinion, it would not be unreasonable for PJM to use a less conservative criterion, more in keeping with its peak load relative to other ISO/RTOs like the New York ISO and ISO New England. For example, just by changing from a criterion of one day in 25 years to one day in 10 years for the Mid-Atlantic LDA, and putting it on the same loss of load expectation basis as New York and New England, PJM could lower the CETO for the Mid-Atlantic LDA by approximately 3,000MW.

There are other, and in my opinion better, ways to do this kind of analysis. For example, when it studies the LOLE of the entire PJM system to calculate the required installed reserve margin, PJM uses a multi-area probabilistic program. It does not model separate areas within PJM, however. PJM could use the same program to model all the LDAs along with the existing transmission transfer capabilities between them, and still target an overall LOLE criterion. A need to increase any of the inter-area transfer capabilities would be evident from such an analysis. Thus PJM could unify the process, and also meet the desired objective vis-à-vis the overall PJM system.

In fact, PJM's process for addressing reliability "need" is far more conservative than necessary. In an earlier case (the proposed Prexy facilities in southwestern Pennsylvania), this overly conservative approach led to a recommendation for a major new 500kV transmission line, which was approved by PJM. In my opinion, such a high voltage facility was clearly unnecessary, and I testified to this during the proceedings. After the state hearings were mostly concluded, the PUC ordered a voluntary collaborative effort. This led to a much simpler, less expensive, and less environmentally intrusive solution involving modifications to the local 138kV system and the addition of shunt capacitors.

The proposed Prexy Facilities were to consist of a new 500kV substation in Washington County called "Prexy", a new 500kV transmission line (36 miles long) in Washington and Greene counties, and three new 138kV lines (running 15 miles) to connect the proposed new substation to the existing transmission system. After the collaborative process, the approved fix reinforced the electric grid without any new 500 kV lines, substations, or 138 kV lines. Instead, it involved installing one new monopole on an existing utility right of way (to allow the connection of two existing lines), adding equipment (capacitors) at five existing substations, and replacing the conductors on 2.5 miles of existing 138 kV lines. The estimated cost for the agreed-upon fix is $11.6 million, instead of $213 million for the proposed Prexy Facilities. And the solution solved the same reliability issues that were "driving the need" for the previously proposed "Prexy Facilities."

PJM's approval of the need for Prexy facilities, and PATH in this proceeding, violated an engineering principle which a former professor of mine used to insist on: "Don't use a pile driver to hammer tacks."

Q. WOULDN'T THERE BE VIOLATIONS OF THE MANDATORY NERC STANDARDS IF PATH IS NOT BUILT?

A. Not at all. Whether or not violations will occur ultimately depends on the value selected for the CETO. This applies to voltage as well as line loading violations. There would be *no* violations of NERC Standards if realistic CETO values were used. The only reason that "violations" were identified in PJM's studies is that PJM was trying to cram too much power from outside (essentially western PJM) into the eastern LDAs by using unnecessarily high CETO values. It's sort of like a mouse trying to swallow a lion. For the Mid-Atlantic LDA, without PATH, a 6,000MW CETO would result in zero violations. Zero. And the Mid-Atlantic area would still be capable of importing over 6,000MW.

As I see it, based on my more than 47 years of experience in transmission planning and reliability assessment, eastern PJM is *already* too dependent on western generation – this is the *real* reliability problem, and a major reliability risk.

In my opinion, PJM faces a reliability problem – a *serious* reliability problem – which will worsen if PATH is built. It's the overdependence of the eastern PJM load centers on generating units hundreds of miles to the west. The megalopolis from northern New Jersey to northern Virginia is over-dependent on long transmission lines, any one of which could be taken out of service by natural or human agents. This is a *major* problem that needs to be addressed. And it's a *national security problem* as well. PJM should, in my opinion, develop a program to address this problem as soon as possible – but instead PJM is pursuing policies that will only make the problem worse.

Q. WOULDN'T PATH, IN AND OF ITSELF, INCREASE RELIABILITY ANYWAY?

A. No. Rather than *increase* reliability, PATH would actually make it *worse*. Eastern load centers from Boston to northern Virginia comprise what urban planners sometimes call a linear city or megalopolis. It's essentially one continuous metropolitan area. Within this linear city, the area from northern New Jersey and Philadelphia to Washington and northern Virginia is part of PJM. If PATH is approved, generating companies will be given a powerful incentive to site new generators in the Allegheny coal fields, hundreds of miles to the west, rather than in or close to the eastern load centers. Even existing coal-fired generators will have the opportunity to ramp up their outputs. This will make the eastern megalopolis even more dependent on remote generation resources than it already is. Cities like Newark, Philadelphia, Wilmington, Baltimore, Washington and Richmond will depend for their electric supply on generators hundreds of miles away. I've been in electric power transmission planning and reliability for more than 47 years, but you don't have to be an engineer to understand that this is a less reliable situation than if the resources were located nearby. It's like running an extension cord down the block to plug your toaster into a neighbor's outlet rather than using an outlet in your own kitchen. The long transmission lines are vulnerable to all sorts of interruptions – including terrorist attack – so this is a national security issue as well as a reliability concern.

More transmission does not equal a higher level of reliability. Consider two hypothetical transmission systems: one a system with a lot of transmission lines, but planned and operated to *less* stringent reliability standards; the other a system with very little transmission, but planned and operated to *more* stringent reliability standards. The first system would be less reliable than the second system, because it uses less stringent reliability standards. <u>Reliability is not a function of the amount of wire in the air</u>.

Now consider what happens when transmission is added. The apparent electrical impedance across the grid is reduced, in effect making it electrically tighter. Thus a given contingency could have a more widespread effect. By increasing the amount of west-to-east transmission in PJM, the proposed PATH line would make the Eastern Interconnection subject to larger blackouts.

This can be visualized in a more technical light. The key factor in the stability of a system is the electrical angle between generators. Building transmission lines reduces the equivalent electrical impedance between generators – the units become electrically closer, and the angle is decreased, which tends to make the system more stable. However, stability will be improved *only if no additional power is scheduled across the system*. If the power flow is increased, then the angle is increased, and the units will be electrically further apart, making the system less stable. My own experience after doing this kind of analysis since the early 1960s is that, even if the impedance is decreased and the power flow increased such that the electrical angles are the same, the system will still be more vulnerable to extreme emergency contingencies – those that are more severe than the criteria used in planning and operations, and which are either the major cause or an important contributing cause of nearly all bulk power system blackouts.

When systems build more transmission only to accommodate higher levels of transfer, they push the system harder. The likelihood of instability is increased; the system is more likely to suffer a blackout if an unforeseen contingency occurs, and the blackout is likely to be larger and more damaging. In my opinion, PJM has not proven a reliability problem that requires the construction of PATH, or that PATH will make the overall system more reliable. However, instead of building the PATH line, reliability could be *improved* by promoting additional generating capacity and other resources in the East, close to the load centers. Lower west-to-east transfers across the PJM system would significantly reduce the angle between generators, making the northeast quadrant of the Eastern interconnection less susceptible to instability and blackouts.

Q. DO YOU THINK THAT PJM PLACES TOO MUCH EMPHASIS ON EXTRA HIGH VOLTAGE (EHV) TRANSMISSION LINES?

A. Very definitely. PJM seems to see EHV AC transmission not as the *best* solution to reliability problems, but as the *only* solution. Under the current PJM cost allocation rules, all transmission facilities at 500kV and higher are “socialized” – i.e. their costs are charged to all the Load Serving Entities (LSEs) in PJM essentially in proportion to their electric loads. This means that all customers throughout the PJM area will pay the construction costs for PATH. Because of this “socialization,” PATH will provide existing and future western generators, including coal-fired generators, with free access to the eastern load centers. In effect, western generators will be subsidized at the expense of the ratepayers. It's also a case of discrimination against generators and other resource providers in the East.

In other words, western generators will be given market access to eastern load centers without having to pay the cost of providing that access. Customers throughout PJM will bear the full cost of the new transmission. Western generators, both existing and future, will be able to compete with eastern resources without paying for the transmission that makes it possible. This will skew the economics of electric generation supply by subsidizing some generators at the expense of others – and ultimately at the expense of ratepayers. This is not the "fair and non-discriminatory" market that FERC envisaged in promoting "deregulation."

Q. IT HAS BEEN SAID THAT TRANSMISSION PROJECTS MUST BE APPROVED EARLY ON, SINCE THEIR LEAD TIMES ARE NOW LONGER THAN LEAD TIMES FOR GENERATORS.

A. That's true, but early approval of transmission has another, unanticipated consequence. Transmission lead times are now longer than the lead times for generators. That means that transmission projects will generally be approved before generators or other resource providers need to make their commitments. In other words, generating companies can wait until a major transmission line is approved or disapproved before deciding whether to build new generating units in the East or West. If a new line is not planned, or a proposed line isn't approved, developers could site new units in the East, where long EHV lines would not be required to reach load centers. On the other hand, if a line *is* approved, developers are likely to build in the West, where it would be less expensive, since they will be provided transmission access to the eastern load centers at no cost to themselves.

Such transmission approvals would foreclose other options, including generators sited in the East, load management systems, and greater reliance on Reliability Pricing Model (RPM) solutions in general.

In summary, PATH would provide a strong disincentive to anyone considering locating generation or other resources in eastern PJM, and a correspondingly strong incentive to build coal-fired generation in western PJM. The seeming obsession with transmission solutions will not only provide an effective subsidy to existing generators in the West, but it will act as a magnet for siting future generators there, as opposed to locating in the East, where they are really needed.

Q. ARE THERE ANY OTHER EXAMPLES OF DISCRIMINATION IN THE ASSUMPTIONS UNDERLYING THE PATH STUDIES?

A. Yes. To me, an egregious example of PJM's discrimination is how the representation of planned, future generators is handled. In its planning studies, PJM represents only those generators which have executed a Facilities Study Agreement (FSA). To be represented in the studies, generators which would contribute toward the solution of a reliability problem must also have executed an Interconnection Services Agreement (ISA), the next step after the FSA. However, generators which exacerbate a reliability problem are represented even if they have *not* received an ISA. This is patently discriminatory, and in my view is a direct violation of FERC's "fair and non-discriminatory" principle. In defense of this procedure, Mr. McGlynn testifies that more than 75% of all proposed generators eventually drop out, but adds that "5% of requests drop out after an FSA is executed." [McGlynn, page 13, line 2] Mr. McGlynn testifies that only 5% of requests drop out between the execution of an FSA and an ISA. *By McGlynn's own admission*, there's very little difference between the number of generators that complete FSAs and those that complete ISAs – a mere 5%.

In my opinion, no distinction should be made. Any generator which has an executed FSA should be represented, regardless of whether it exacerbates or solves reliability problems. To intentionally discriminate against the very generators which could solve reliability problems is both foolish and potentially costly. It goes against one of the most important principles of FERC and deregulation – that all generators must be treated in a manner that is both fair and non-discriminatory. Finally, again in my opinion, it represents very poor engineering. Good engineering is premised on even-handedness – PJM's biased handling of future generators, based on whether each would contribute to a problem or its solution, tilts the science toward a presumably desired conclusion which might not be proven by a fair and non-discriminatory approach. This constitutes a bias towards transmission and in favor of western coal-fired generators and against eastern generators and other resources; it is not even-handed at all. Political and economic motives should not be permitted to interfere in the engineering. As I say in my courses, "When the Laws of Physics and the Laws of Economics collide, Physics wins."

Q. DID THE APPLICANTS CONSIDER SUFFICIENT ALTERNATIVES TO PATH?

A. The testimony of the applicants' witnesses indicates that the only alternatives seriously considered during the 2007 RTEP were other AC EHV transmission lines. No alternatives involving non-transmission resources (generation, additional DSM, etc.) in the East, close to the load centers, were examined, even though they might offer distinct advantages in terms of cost, reliability, and environmental impact. Little recognition seems to have been paid to PJM's Reliability Pricing Model (RPM) process – despite the fact that one of its stated purposes is to provide incentives for generators to locate near the eastern load centers. PJM argues that it is not permitted to *order* anything other than transmission – but it certainly could develop policies that would *encourage* non-transmission solutions. Eastern resources seem to rate second-class status as compared to AC EHV transmission. No attention was even paid to transmission alternatives other than alternating current (AC) 500 and 765kV. High Voltage Direct Current (HVDC) alternatives were totally ignored in 2007 – despite HVDC's obvious advantages, and its utilization for other projects in PJM (e.g. Neptune and MAPP). PJM's planning process seems to be wearing blinders – any alleged reliability problems will be addressed by the "same old same old" EHV transmission solutions.

Somewhat belatedly, a "PATH HVDC Conceptual Study" has been initiated. Since this was not mentioned in any of the witnesses' testimony, we can safely conclude that HVDC was not considered as an alternative while the PATH studies were being conducted, and not evaluated at the time the decision was made to recommend PATH as a 765kV, AC project.

In addition, PJM's 2009 "re-tool" cases came up with different limiting elements than those relied on for the "need" assessment. These were generally on lower voltage facilities, and occurred further out in time. These differences alone should have suggested that other alternatives need to be explored. But they did not. In brief, the need for PATH was based on problems that no longer exist.

Q. WOULD YOU COMMENT ON PJM'S ONE-AT-A-TIME TRANSMISSION PLANNING?

A. I would describe PJM's approach to solving its alleged reliability problems as a piecemeal one. In recent years, we've witnessed a succession of proposals to build EHV transmission projects in PJM, each designed to solve a list of alleged reliability violations. It seems that no attempt is made to address the problems on an overall, integrated basis. Once a project is approved, it becomes cast in concrete. We're told it will take care of everything. Until the next one, that is. There never seems to be an attempt to look at what combination of solutions could solve *all* reliability problems/violations with a single overall solution or a set of integrated solutions. Nor does there appear to be any attempt to examine whether a new proposal, perhaps with some modifications, might obviate the need for one already approved.

It seems to me common sense that planning on a piecemeal basis will inevitably result in more facilities being built than would really be necessary to meet the requirements of NERC and other reliability standards. Perhaps a simple, hypothetical example will make this more understandable.

Let's assume that a planning entity follows a "piecemeal" approach. It studies its system, identifies certain reliability violations, and determines that a particular new facility would solve them. Let's assume it gains approval for that facility, and adds that facility to its base assumptions. It then begins another reliability study, and discovers another set of violations. A second facility is planned to fix these violations – it's also approved, and added to the base. A third study is conducted, and a third set of violations appears – and a third facility is identified and added to the base system. And so on through, let's say, seven studies and seven facilities. Is it not common sense that, had the planners looked at the *entire* system, and identified *all* reliability violations, they would almost certainly have been able to develop an "integrated," multi-facility solution which included *fewer* required elements than the earlier, piecemeal approach? A piecemeal approach is neither the best nor most efficient way to plan a system – more facilities will invariably be found to be "needed" than truly would be. That's because the second (or third or fourth) facility may prove to be an efficacious solution to the problems which drove the need for the first (or second or third). The net result will be an overbuilt system, with all the attendant economic, social and environmental consequences.

This bias or tendency toward "piecemeal," one-at-a-time transmission planning is a grave weakness of the current RTEP process in PJM.

Further, the piecemeal, cast-in-concrete approach forecloses other options. Each new facility goes into all the models, and is assumed in place for all the capacity auctions. Even the possibility of delay or cancellation is ignored. If *uncertainty* is viewed as an important factor for the representation of new generating units, it should also be included for proposed transmission additions.

There's another problem here. Once PJM, acting as the RTO, has identified one or more violations, it goes to the appropriate transmission owners (TOs) in whose systems the violations occur and in effect orders them to develop a solution. This kind of Balkanization does not serve the interests of overall reliability with minimum expenditure for new facilities. It's essentially a corollary to piecemeal, one-at-a-time planning. It seems to me that PJM should be more involved in developing overall solutions – and taking a second look at prior solutions, too.

Q. WOULD ADDING TRANSMISSION CAPACITY INTO THE EASTERN LOAD CENTERS MAKE THEM MORE RELIABLE?

A. No. Not if the added transmission results in the load centers being more dependent on remote generation. The more Philadelphia, Baltimore, Washington and Richmond must depend on long distance transmission, the more vulnerable they will be. And lower reliability is an inescapable consequence of greater vulnerability.

A further note. PJM seems to want to build a transmission system capable of delivering every MW from any generator anywhere on the system to any load point in PJM – regardless of reliability need or system conditions at the time. But that's not necessary for a reliable, or even an economically optimum system. On a reliability basis, comparable plans or options would include sufficient transmission capability to maintain an appropriate Loss of Load Expectation overall.

PJM could use Loss of Load Expectation techniques to compare generating capacity and other resources sited close to the load vs. less expensive generation more remote from the load, including the constraints of the intervening transmission system. Economic analyses would consider combinations of greater or lesser percentages of remote and local generation. However, the cost of necessary new transmission, plus incremental system losses, should be included. These costs would, of course, be much higher for remote generation, which would tend to offset any economic advantage it might otherwise have. Yet neither the applicants nor PJM has conducted any such analysis.

Q. IS PATH, IN YOUR OPINION, REALLY ABOUT RELIABILITY?

A. No. PATH is more about economics than reliability. When added to the present import capability in excess of 6,000MW, there is more than enough generating capacity within the constrained Mid-Atlantic LDA to supply all the load all the time. Thus there is no reliability need to increase the import capability by about 2,000MW – from 6,240MW to 8,190MW. This would involve operating more expensive, local generation more frequently; however, reliability would be enhanced, since the Mid-Atlantic LDA would be less dependent on generating capacity hundreds of miles away. Such an approach is called "transmission constrained dispatch," or the use of "out of merit" generation, and is consistent with how the system is actually operated. It's commonly used by most power systems in North America in both planning and operations. It would reduce the chance of widespread interruption, whether from human error, equipment failure, *force majeure*, or terrorist attack. Any increase in generation costs would be offset by savings in transmission construction, at least in part. Finally, and perhaps most important, this case is supposed to be about *reliability*, not *economics*.

In my opinion, PATH isn't just about economics *in general* – it's about *coal-fired* economics. This is clearly illustrated by a presentation made by Mr. Karl Pfirrmann at a FERC Technical conference on May 13, 2005. At the time, he served as President, PJM Interconnection, L.L.C., Western Region. In his Executive Summary, Mr. Pfirrmann describes "the potential for new transmission resources in the region to enhance opportunities for coal based generation to reach eastern markets." The proposal is called Project Mountaineer, and includes "potentially 550 to 900 miles of new backbone 500 or 765 kV transmission at an approximate cost of $3.3 to $3.9 billion." In his written comments, Pfirrmann describes this as a "new initiative … to utilize our regional transmission planning process to explore ways to further develop an efficient *transmission 'super-highway' to bring low cost coal resources to market*." [Emphasis added.] Mr. Pfirrmann also hails "dramatic increases in the amount of power flowing from this region into 'classic' PJM, including from coal-based generation," and offers an exhibit illustrating a 35-40% increase since PJM's expansion to the west.

We can gain some perspective on this by considering PATH's predecessor. An EHV line from Amos to eastern PJM was proposed before any "violations" had been indicated. This was in connection with Project Mountaineer, as discussed above. As suggested by Mr. Pfirrmann, Project Mountaineer's original goal was to provide access to eastern markets for an additional 5,000MW of western generation. The TrAIL and PATH projects, taken together, are remarkably consistent with such an intent. Some might ask, if PATH is approved, what will be next?

Q. WHAT IS YOUR VIEW OF THE VOLTAGE STABILITY PROBLEMS CITED BY MR. McGLYNN?

A. PJM has not proven that the alleged "voltage instability" is a legitimate problem. Mr. McGlynn goes to considerable length to establish voltage instability, but his only evidence – so-called "knee-of-the-curve" analyses – is incomplete. No transient stability results have been shown. "Knee-of-the-curve" analysis is useful as a screening tool, but voltage instability can only be proven by rotor-angle stability analysis in which the dynamic response of the overall system to a sudden disturbance is simulated in the time domain. Neither the applicants nor PJM have presented any such stability results. And all of the cited violations occur at CETO values that I consider to be unnecessarily high. Mr. McGlynn's testimony confirms that there are no voltage issues until transfers into the Mid-Atlantic LDA are well above 6,000MW.

Q. WHAT ABOUT STEADY STATE VOLTAGES, BOTH ABSOLUTE VOLTAGES AND VOLTAGE DROP?

A. Whatever voltage problems may exist might be solved by power factor correction. Low voltage problems, whether on an absolute or a voltage drop basis, are generally an indication that reactive (MVAR) loads are too high relative to active (MW) loads. This is reflected by low power factors – i.e. the ratio of MW to MVA. Reactive (MVAR) load is a natural part of power system load, and comes from various apparatus on customers' premises. It can be reduced by the installation of shunt capacitors or static VAR compensators (SVCs), which supply reactive power. Failure to adequately compensate for reactive load means higher MVAR loads as seen from 115kV and 138kV substations, hence lower power factors. Basically, what happens is that the high reactive loads have to be supplied from remote generators and the EHV system, essentially dragging MVARs through all the impedances of the various transmission lines and transformers. This results in larger voltage drops. [A close approximation of voltage drop can be determined by multiplying the per-unit inductive reactance of a line or transformer times the per-unit MVAR flow through it.] Further, the higher power flows through all the lines and transformers will result in higher reactive (MVAR) I^2X losses, and the consequent need to pull even more reactive power off the EHV system, which leads to larger voltage drops, etc. This phenomenon will only get worse as load grows. The best place to correct power factor is to place shunt capacitors on the subtransmission and distribution system – as close to the load as possible.

Many of the Mid-Atlantic buses listed in PATH's response to SierraVA-IV-51 have power factors below 95% – despite the fact that PJM Manual 14B, Appendix D: "PJM Reliability Planning Criteria" calls for a minimum power factors of 97%.

Power factor correction is in essence a reduction in reactive (MVAR) load, generally by adding shunt capacitors on the distribution and/or subtransmission systems. If this is impractical for some reason, shunt capacitors can be added at 115 and 138kV substation. If for any reason even *that* is impractical, the applicants themselves have suggested the solution – shunt capacitor or SVC additions at higher voltage stations.

Power factor correction (reactive compensation) is an ongoing process – it has to be continued year after year as system load grows. It's part of the continuing obligation of providing good utility service. The applicants do not seem to have examined if the voltage problems could be fixed by improving power factors. Nor have they examined the possibility of adding switchable shunt capacitors to some of the 115/138kV substations. We have been told that a "high level" investigation was made which considered adding shunt capacitors at 500kV and 230kV substations without PATH, and this was deemed to be too expensive. But applicants' witnesses in other states have testified that more than 1700MVAR of shunt capacitance will be required at both terminals of the proposed PATH line! (See Dr. Hyde Merrill's testimony.) In any case, no description of the nature of this "high level" investigation was provided. Without a presentation of the results of power factor and lower voltage substation studies, and an explanation of the reactive additions needed by PATH itself, the alleged voltage problems cannot be proven.

Q. PLEASE DESCRIBE SOME OF YOUR OVERALL IMPRESSIONS OF THIS CASE.

A. PJM and the applicants demonstrate a distinctly "one track mind" in their planning. Alternatives involving means other than an AC EHV transmission line have not been explored – this is true despite the fact that the problems discovered in the 2009 analyses depict dramatically different limiting facilities than those uncovered in 2008. In fact, the 2009 "re-tool" cases came up with a very different set of problems, were less severe, and occurred further out in the future. To most planning engineers, this would suggest that other possible solutions should be examined, but no such attempt has been made. This is especially true if the conclusions are the result of extrapolation. The original PATH proposal remains unchanged, and alternatives remain unexamined.

There's a built-in bias against any other approach; e.g. the way representation of new generators is handled strongly discourages serious consideration of non-transmission alternatives. Even in the area of transmission itself, no alternatives other than 500 and 765kV AC have been examined. A strong case can be made that no additional transmission is needed. But even if additional transmission *is* needed, why hasn't PJM considered building PATH as, for example, an HVDC line? Or why hasn't the conversion of an existing AC line (such as the Mt. Storm-Doubs 500kV line, as suggested by Mr. Merrill) been considered?

As pointed out by my colleague, Dr. Hyde Merrill, all conclusions beyond the study year of 2014 were based on extrapolation from 2014 results. It's almost inconceivable to me that the need for a major transmission facility, costing in the neighborhood of $2 billion, would be based on extrapolated results. Extrapolation is also inconsistent with NERC's requirements for long-term studies. As I indicated earlier, the purpose of long-term studies is to provide some indication of the nature and direction of future reliability problems, and to ensure that any recommended short-term solutions will be consistent with future needs. Extrapolation does not, in my view, satisfy that requirement. AEP and its partners seem to have refused to "think outside the box." Perhaps PATH's emphasis on AC EHV transmission, and the effective subsidization of western generation, reflects the potential profits that could be made from transmission usage charges, as well as AEP's ownership of major significant western generating resources. A major facility like the PATH line should not be approved based on extrapolation.

To summarize:

• In my opinion, there's a major problem with PJM's present RTEP/CETO process of assessing reliability. The assumptions are too conservative, and lead to requirements beyond what would be needed for good reliability.

• PATH would discriminate against eastern generation and other potential resources, and promote western generation, by providing the latter with free access to eastern load centers – all at the expense of the rate-payers.

• Whereas the rest of the industry utilizes a loss of load expectation of one day in 10 years, PJM uses one day in 25 years to determine the import capability required by each Load Deliverability Area (LDA) – which can be quite large. The Mid-Atlantic LDA, for example, has a peak load in excess of 60,000MW. This makes it equal in size to the combined neighboring New York and New England ISOs. Assumptions more in line with the industry, rationalized to a reliability standard equivalent to that used by New York and New England, would result in a CETO which would be lower than the point at which the first reliability violations occur. In other words, there would be no NERC violations.

• Without this overly conservative approach, CETO values would be lower and there would be no NERC violations. Hence there is no demonstrated need for PATH.

• Reasonable alternatives, both non-transmission and even transmission, were not considered despite their potential advantages in terms of cost, reliability, and environmental impact. The applicants did not consider any reasonable alternatives based on the currently identified (April 2009) issues.

• By increasing the dependence of the eastern load centers on remote generators and transmission lines hundreds of miles long, PATH would actually lower reliability. This is the *real* reliability problem in PJM. Further, the increased reliance on very long transmission lines is a national security issue.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MISO IMM Comments on LRTP Tranche 2 Benefit Metrics

MISO Independent Market Monitor

David Patton, Ph.D.
Potomac Economics

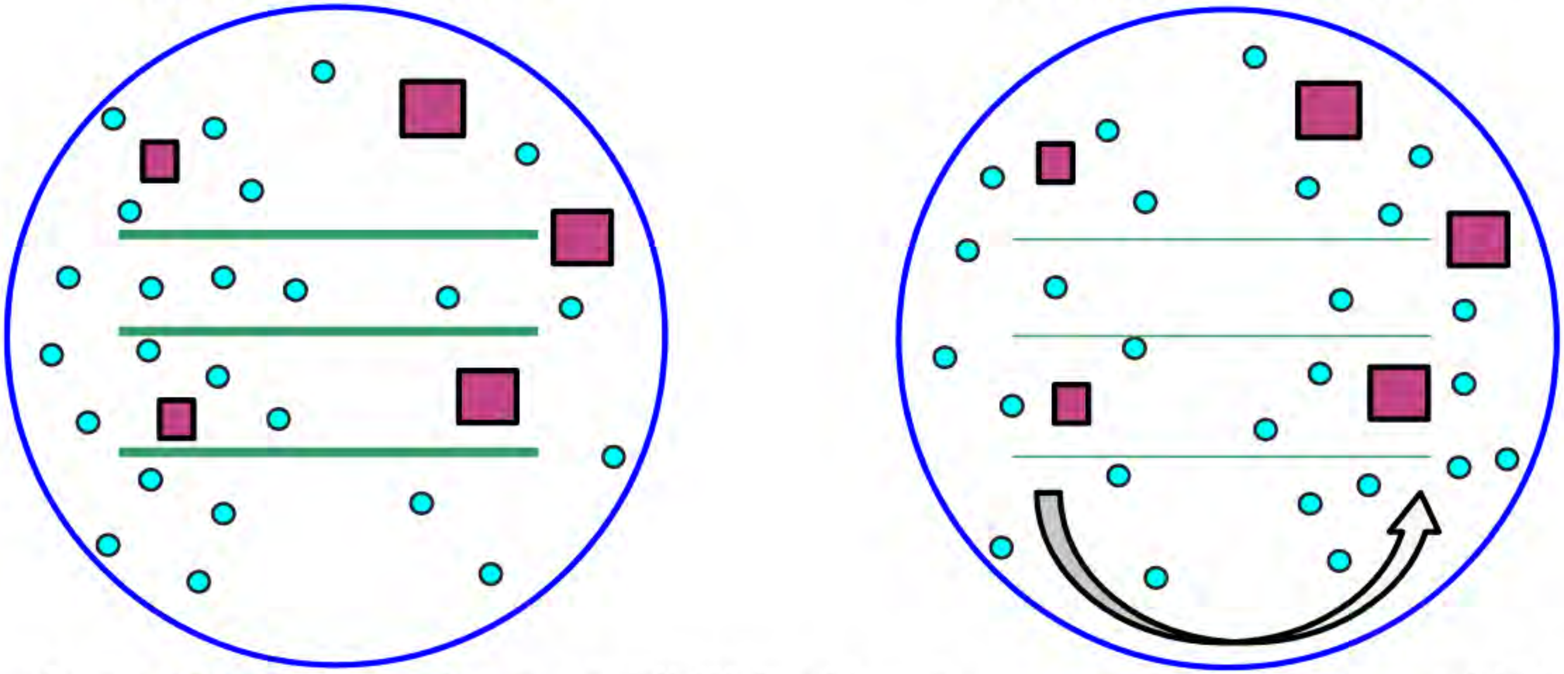
May 29, 2024

Comments on Analysis of Transmission Benefits

- Transmission investment will be a critical component of MISO's evolution over the next 20 years.
- It is important that this investment be economic –
  - ✓ Uneconomic investment will raise costs and undermine investment in resources, storage and other alternatives to transmission.
  - ✓ We have previously expressed concerns about the unrealistic nature of Future 2A growth assumptions.
  - ✓ MISO has chosen not to attempt manual optimization (evaluating alternative siting impacts on individual projects or to resolve overloads).
  - ✓ The benefits methodologies are likely to lead to substantially over-estimated benefits, which we describe in this presentation.
- One of our primary concerns is related to the fact that the effects of MISO's markets are not properly recognized as illustrated below.

Recognizing the Market Effects in the Benefit Analyses

With Tranche 2 | **Without Tranche 2**



- One of MISO's main responsibilities is to operate markets that provide key economic signals to guide generation investment and retirement decisions.
- Benefit analyses must recognize that new transmission will change energy and capacity market signals – less transmission will shift resources closer to load.
- This will reduce or eliminate many of the benefits (e.g., capacity savings and reduced losses).

Classes of Transmission Benefits

- MISO has proposed 9 classes of transmission benefits.
- Classes that are likely to be valid and reasonable, depending on the details:
  - ✓ Congestion and fuel costs savings
  - ✓ Reduced transmission outage costs
- Classes for which we have significant or fundamental concerns:
  - ✓ Avoided capacity costs
  - ✓ Decarbonization
  - ✓ Mitigation of reliability issues
- Classes that are may be overestimated depending on the methodology
  - ✓ Capacity savings from reduced losses
  - ✓ Energy savings from reduced losses
  - ✓ Avoided transmission investments
  - ✓ Reduced risks from extreme weather events
- This presentation discusses our comments on each class of benefits.

Congestion and Fuel Costs Savings

- This class of benefits is the most valid and represents the truest measure of the economic benefits of transmission
- **Concerns**: Although it is the most valid, it depends heavily on the input used to ensure the savings are accurate. Some factors that would tend to reduce these benefits may not be included in MISO's methodology.
- **Recommendations**:
  - ✓ Develop a reference case that modifies siting assumptions to simulate market responses without Tranche 2. Siting would locate new additions inside of congested areas (closer to load, in capacity import limited areas, at raise help locations).
  - ✓ Include the effects of AARs on the existing network facilities.
  - ✓ Model the contribution of storage in reducing peak transmission flows and congestion since mitigating congestion is a significant component of the business case for storage.

Reduced Transmission Outage Costs

- **Comment**:
  - ✓ This benefit is a potentially valid class of benefits since the base production costs savings would not tend to include transmission outages that are experienced regularly.
  - ✓ However, the magnitude of this estimated benefit is highly uncertain.
- **Recommendation**:
  - ✓ MISO should adopt a conservative approach to estimating this benefit that reflects the historical effects of outages.

Avoided Capacity Cost

- **Concern**: There is little basis to assume that transmission will affect MISO's capacity requirements.
- The extent to which resources are deliverable *will* affect the amount of capacity needed, but the markets provide incentives to be deliverable.
- However, the MISO methodology:
  a. Creates a base case with sufficient generation to meet 1-in-10 on a copper sheet, but the generation is not deliverable.
  b. Adding in the network makes it appear that more capacity is needed to meet 1-in-10 since the assumed generation is not fully deliverable.
  c. Tranche 2 makes the generation much more deliverable so capacity needs are lower than in (b).
- This is not a valid benefit because, absent the transmission, markets will motivate/require generation in deliverable locations closer to load.
- **Recommendation**: i. Eliminate this benefit or ii. Develop alternative case with modified siting assumptions and calculate cost of *moving* resources.

POTOMAC ECONOMICS

Decarbonization

- **Concern**: The congestion and fuel savings include the PTC values, which fully reflects the value of decarbonization, so calculating an additional benefit is double counting.
  - ✓ The PTC is the most reasonable benchmark for the value of carbon since it is law and represents what the government will actually pay.
  - ✓ The PTC corresponds to a carbon value of ~$50/ton. The Biden administration's value of carbon is $51/ton, which is being litigated.
  - ✓ EPA has proposed almost a 4-fold increase, almost all of which is based on lowering the discount rate from 3% to 2% percent based on falling interest rates up to 2021. Rates have been rising since then to > 4%.
  - ✓ MISO has no basis to impose a cost higher than the PTC on its customers when there is no consensus that the PTC undervalues carbon.
- **Recommendation**: Eliminate this benefit class as it is already captured in the production cost savings.

Mitigation of Reliability Issues

- **Concerns**:
  - ✓ Quantifying this benefit by assuming MISO will shed load to address voltage or other issues (without Tranche 2) is not realistic.
  - ✓ In reality, these issues are addressed by thermal proxies, reconfigurations, or by investments in other equipment that would be much less expensive than load shedding.
- **Recommendation**:
  - ✓ Eliminate this class of benefits; or
  - ✓ Quantify cost based on the next operating action to address the issues if transmission is not built (not load shedding):
    - – Congestion from modeling a thermal proxy; or
    - – The costs of equipment to address the issues (e.g., voltage support).

Capacity and Energy Savings from Reduced Losses

- **Concern**:
  - ✓ In principle we agree that new higher voltage transmission will reduce losses;
  - ✓ BUT, the loss reductions should reflect the fact that resources will relocate closer to load without the Tranche 2 projects.
- **Recommendations**:
  - ✓ Develop alternative reference case that modifies siting assumptions to reflect market responses without the portfolio.
  - ✓ Siting would locate new additions closer to load, in capacity import limited areas, and at raise help locations.

Avoided Transmission Investment

- **Concerns**:
  - ✓ Avoided transmission maintenance/replacement could be a valid benefit.
  - ✓ Avoided transmission investment that is hypothetically needed to address congestion would be inappropriate unless:
    - Avoided benefits are quantified and deducted from the avoided capital costs.
- **Recommendation**:
  - ✓ Include only maintenance/replacement projects (age and condition) that would be avoided.

Reduced Risks from Extreme Weather Events

- **Concern**:
  - ✓ This is one of the most uncertain and speculative benefits.
  - ✓ Each of the extreme weather events have resulted in extremely different patterns of flows so it is difficult to predict how transmission would help.
  - ✓ The benefits should be small because the probability of extreme weather events are low.
- **Recommendation**:
  - ✓ MISO should ensure that it does not implicitly increase the probability of extreme weather events in calculating the benefits.
  - ✓ Benefit = Potential Savings during Event * Probability of Event.

POTOMAC ECONOMICS

Other Comments on Benefit Estimates

- We have additional recommendations to improve the benefit estimates.
- Divide the portfolio into groupings of projects that address separate issues to validate that each grouping passes a benefit-cost test.
  - ✓ Assessing the entire portfolio together would not allow MISO to pair it down so that it only includes the economic groupings.
- Adopt a sensitivity case similar to IMM-2A, which has more dispatchable/storage/hybrid resources than MISO's Future 1A.
  - ✓ Although Future 1A has substantially less intermittent renewables, it also understates the likely quantity of dispatchable resources that are key for managing congestion.
- Consider improving a) the siting of resources based on the location of congestion, and b) the modeling of battery storage to resolve congestion.
  - ✓ MISO should examine whether the congestion identified in reference case can be more economically be managed with storage to verify the robustness of the business case.

In urging the Commission to reject the results of that "long, rigorous, and iterative"[71] process, the parties to the Stipulation are asking the Commission to undermine public confidence in its integrity. Xcel had wanted to build two new combustion turbines, but agreed to postpone a determination on their approval after the process demonstrated that they weren't yet necessary and intervenors were concerned about their cost and environmental impacts.[72] Instead, the Commission found that "it is more likely than not that there will be a need for approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029."[73] Because Xcel "systematically overestimates demand and underestimates costs,"[74] the Commission reiterated multiple times in its order that 800 MW was the maximum capacity that could be acquired pursuant to that IRP order.[75] Accepting the Stipulation would require the Commission to reject its own unambiguous order, which was informed by significant public input, in the name of expediency.

Xcel argues that the Commission's language does not mean what it says, first quoting the Commission's "not more than 800 MW" and immediately stating that this somehow meant "more or less than 800 MW."[76] To be clear, the Commission stated three separate times that 800 MW was the maximum firm dispatchable capacity to be acquired in its 2022 IRP order.[77] The Commission then reiterated this in its order authorizing the instant bidding process one year ago,

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Compliance Filing, and Setting Requirements for 1995 Resource Plan Filing at 2-3 (Jul. 15, 1994); 2006 RFP Order at 2.
[71] 2022 IRP Order at 12.
[72] *Id.*; Docket No. E-002/RP-19-368, Supplemental Comments of the Clean Energy Organizations at 12-30 (Oct. 15, 2021); *see also* Docket No. E-002/RP-19-368, Public Comment of Institute for Local Self-Reliance et al. (Oct. 15, 2021).
[73] 2022 IRP Order at 32.
[74] *Id.* at 11; Docket No. E-002/RP-19-368, Supplemental Comments of the Department of Commerce at 9 (Oct. 15, 2021).
[75] 2022 IRP Order at 14, 32.
[76] Xcel Comments in Support of Stipulation at 22.
[77] 2022 IRP Order at 14, 32.

One alternative will consider the implications of using biomass gasification at the third boiler. Gasification may prove to be a superior technology because of its low emissions, relative cost, and suitability for the specific type of cyclone boiler at Bay Front, which cannot effectively burn chipped or shredded wood. If the study demonstrates that biomass gasification is a viable option and the Company converts the plant, Bay Front would become one of the largest biomass-fueled plants in North America. We expect to complete our studies in late 2008, and if feasible, a filing to the Commission describing the findings and recommendations will be made at that time.

Red Wing and Wilmarth Plants

Both plants are located south of the Twin Cities area. The Red Wing plant is located in Red Wing, Minnesota and the Wilmarth plant in Mankato, Minnesota. Both plants have two 10 MW generating units and burn processed municipal solid waste, called refuse-derived fuel ("RDF").

Both plants were built in the 1940s as coal-fired generating facilities. They were both converted in the late 1980's to burn RDF. The processed municipal solid waste provides a low-cost fuel alternative to generate electricity and reduces the amount of material going to landfills. Both plants employ scrubbers with fabric filter baghouses to meet their respective emissions permits. The scrubbers treat flue gas with water and hydrated lime, while the baghouses trap particulate by forcing flue gas streams through large filter bags. These systems are considered to be best available control technology ("BACT"), which allows energy production from Red Wing and Wilmarth to be counted toward the RES.

The RDF for both plants is produced at resource recovery facilities in Newport and Elk River, Minnesota. The fuel supply contract for Red Wing and Wilmarth runs through 2012 as does the book life of these facilities. For capacity planning and RES compliance planning purposes, we are assuming that Red Wing and Wilmarth will be retired at the end of 2012. During the intervening years, we will work to renegotiate fuel supply arrangements and evaluate whether to refurbish these facilities after 2012, or retire them. Such decisions will depend on whether a new fuel supply contract proves to be reliable and cost-effective as well as evaluating the condition of plant equipment. We anticipate providing the Commission with an update on plans for Red Wing and Wilmarth in our next Minnesota Resource Plan filing, presumably in 2009 or 2010.

French Island Generating Plant

The French Island Generating Plant is located in LaCrosse, Wisconsin, on the Mississippi and Black rivers. Units 1 and 2 burn wood waste, railroad ties and RDF. Units 1 and 2 combined produce 25 MW. Units 3 and 4 are 1970s-vintage oil-fired combustion turbines. These units each have the capability of producing 72 MW (summer) and 100 MW (winter). The plant was built in the 1940s as a coal-fired generating facility with Units 3 and 4 converted in 1972 to burn oil, a cleaner fuel. However, within two years after the conversion, the oil embargo caused oil prices to significantly increase, and the units were fired less frequently because they had become expensive to operate.

By the early 1980s, we identified a new low-cost fuel in waste wood, and converted Unit 2 to a fluidized bed boiler to burn it. In addition to reducing operating costs, burning wood helped solve a waste disposal problem by using sawdust and wood chips that otherwise would have been buried in a landfill. For similar reasons, in 1987, the Company built a facility adjacent to the generating plant to process municipal solid waste into RDF. The necessary fuel handling modifications were made to the plant and Unit 1 also was converted to a fluidized bed boiler, making both units capable of burning a blend of waste wood and RDF. The conversion helped extend the life of the plant and maintain reasonable electric rates for customers, while resolving a solid waste disposal problem for La Crosse County.

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April 1, 2025

Will Seuffert
Executive Secretary
Public Utilities Commission
121 – 7th Place East, #350
St. Paul, MN 55101

eFiled and email: consumer.puc@state.mn.us

RE: Supplement to Initial "NEED" Comment and/or early Reply Comment
The Prehn Family & NoCapX 2020
Mankato-Mississippi Transmission Line f/k/a Wilmarth-N Rochester-Tremval
PUC Certificate of Need Docket CN-22-532

Dear Mr. Seuffert:

I'm submitting this Supplement to our Initial Need Comment and/or early Reply Comment in response to email correspondence with MISO's attorney, Jeff Small, who has issues with our filing of Attachment A, claiming "It is deceptive to remove the identifying information on the testimony."[1] **Nothing was removed.** I filed Mr. Loehr's PATH Testimony as found posted by Earthjustice, linked below.[2] The specific Earthjustice and Virginia State Corporate Commission links and docket identification below should satisfy Mr. Small's query and inform this record.

In a convivial conversation with Mr. Loehr, he noted that it was the Virginia PATH docket in which this testimony was filed. A three second google with "Virginia" as a term turned up that Virginia PATH docket – Virginia State Corporation Commission docket PUE-2009-00043.[3] The Virginia SCC denied the PATH application, in part because need was not demonstrated, which is very rare for any transmission docket.

Prior to filing our Initial Comment, I had also found Loehr's testimony in hearings of the Senate Energy and Natural Resources Committee from July 31, 2008,[4] posted on northbyram.org by

[1] Small email, 9:15 a.m., April Fools Day, 2025.
[2] https://earthjustice.org/wp-content/uploads/loehr-testimony.pdf I knew it was Earthjustice as I'd attended a Sierra transmission conference in Virginia in the spring of 2009. See https://www.sierraclub.org/sites/www.sierraclub.org/files/sce/maryland-chapter/Chesapeake/2009%20Autumn.pdf
[3] https://www.scc.virginia.gov/docketsearch/DOCS/208y01!.PDF
[4] Senate Energy and Natural Resources Committee from July 31, 2008 http://www.northbyram.org/routeb/pdf/loehr_testimony.pdf

Scott Olson of the Route B group, a group I'd worked alongside when representing Stop the Lines, challenging the Susquehanna-Roseland 500kV transmission project in New Jersey. See Attachment E, Loehr Testimony – Senate Energy and Natural Resources Committee, July 31, 2008, and linked. In that Senate Testimony, Loehr presents the Nutshell version of his points, succinctly defining the issues – issues which I've seen in every one of the transmission proceedings I've worked on over the last 29 years:

> • *The confusion of reliability with economics – of reliability needs with economic wants;*
>
> • *The assumption that the mere addition of transmission will improve grid reliability. It won't. In fact, more transmission can actually degrade reliability if it is used to accommodate higher power transfers over long distances;*
>
> • *The misapplication of national reliability standards promulgated by the North American Electric Reliability Corp. (NERC), the organization designated by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) mandated by EPAct;*
>
> • *Blackout "scare tactics" intended to frighten customers and public officials, compelling them to endorse the construction of facilities or implementation of policies which are not required to preserve or enhance reliability.*

Id., p. 2-3.

> *The passage of the Energy Policy Act of 2005 (EPAct) was heralded as a major step forward in improving the grid and reducing the likelihood of large blackouts. One drawback, however, is its almost exclusive focus on transmission. It does not address generating capacity sited close to the load centers, or demand side management programs. These strategies are often preferable to transmission as a means of improving overall system reliability. They have the added benefit of adding to the system's installed reserve margin. My own experience over the years has indicated that a certain minimum amount of capacity – in the neighborhood of 80% of the peak demand – must be located within a load center to provide voltage/reactive power support, black start capability, network security, etc.*

Id., p. 2. It's all about distributed generation – we don't need more and more high voltage, expensive, and long transmission lines. It's that simple.

As Mr. Loehr stated earlier today, "it's really not an engineering issue – it's a matter of common sense." I so agree. Common sense is sorely needed in transmission need determinations.

Very truly yours,

Carol A. Overland

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Attorney for the Prehn Family and NoCapX 2020

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Hearings of the Senate Energy and Natural Resources Committee
July 31, 2008

I wish to thank the members of the Energy and Natural Resources Committee for the privilege of speaking to you about several issues of great importance for the future of our nation, and of great concern to me personally. I especially want to express my thanks and appreciation to Senator Bingaman and Senator Dominici of my adopted state of New Mexico, and to Senator Casey of Pennsylvania – along with their staffs.

My name is George C. Loehr, and I'm an engineer with more than 45 years of experience in the electric power industry. My primary expertise is in bulk power transmission system planning and analysis, and electric power system reliability. I was deeply involved in various post-hoc studies following the major blackouts in 1965, 1977, and 2003.

I worked as Executive Director of the Northeast Power Coordinating Council (NPCC) from 1989 to 1997, and was very active in regional, national and international activities. I took early retirement from NPCC in 1997, and now do management consulting, appear as an expert witness, write, and teach a variety of courses on power systems.

I have been a Vice President and member of the Board of Directors of the American Education Institute (AEI), and a charter member of Power Engineers Supporting Truth (PEST). At present, I serve as Chair of the Executive Committee of the New York State Reliability Council (NYSRC), and as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC).

I hold an advanced degree in English Literature along with my Bachelors in Electrical Engineering, and have been deeply involved in the arts for most of my life; for example, I recently published my first novel, *Blackout*, available through <lulu.com>.

A one-page bio is appended to this statement.

The opinions I express in my testimony are entirely my own, and do not necessarily reflect the views of any of my employers or clients, past or present.

……………………………………………………………………………………...

Arguably, nothing is more critical to the future of the United States and its citizens than a reliable electric power system. It can be said without exaggeration that electricity is the bloodstream that sustains our nation and allows it to live and prosper. As the major blackouts of the past have demonstrated, any interruption to power supply adversely affects our economy, our safety and comfort, and our national security. And the most vulnerable part of our power supply is the high voltage bulk power system – the grid. However, it is not the only critical part of a reliable electric system.

Actually, there are three separate "grids" in the continental U.S. – four, if we consider Canada as well. The Eastern Interconnection is the largest, stretching from the Atlantic Coast roughly to eastern Montana, Wyoming, Colorado, and New Mexico. It includes the Canadian Maritime Provinces, as well as Ontario, Manitoba, and Saskatchewan. The Western Interconnection runs from there to the Pacific Coast, and includes the Canadian provinces of Alberta and British Columbia, as well as a small portion of the northern Baja in Mexico. The ERCOT Interconnection comprises approximately 85% of the state of Texas, and the Quebec Interconnection consists of that province in its entirety.

The passage of the Energy Policy Act of 2005 (EPAct) was heralded as a major step forward in improving the grid and reducing the likelihood of large blackouts. One drawback, however, is its almost exclusive focus on transmission. It does not address generating capacity sited close to the load centers, or demand side management programs. These strategies are often preferable to transmission as a means of improving overall system reliability. They have the added benefit of adding to the system's installed reserve margin. My own experience over the years has indicated that a certain minimum amount of capacity – in the neighborhood of 80% of the peak demand – must be located within a load center to provide voltage/reactive power support, black start capability, network security, etc.

If we wish to address electric power energy issues, we must address them in a more comprehensive manner. At present, the EPAct, and policies adopted thereunder, encourages the construction of new transmission not needed for reliability. It subsidizes remote generators, discriminates against local and distributed generation and demand side resources, forces many customers to pay for someone else's benefits, increases the likelihood of blackouts, and makes our grids more vulnerable to terrorist attack.

I believe that decisions on whether particular transmission lines are needed for reliability are best addressed by the states and by the eight existing regional reliability councils. They have consistently done a good job on this in the past. I do not believe that either DOE or FERC has the experienced staff or other resources to do this as well as the regional reliability councils and the states.

Since the passage of EPAct, some misguided proposals have been made to advance corporate agendas rather than serve the well-being of ordinary customers – mainly by trying to get proposed high voltage transmission lines approved as essential to reliability. The most significant are:

- The <u>confusion of reliability with economics</u> – of reliability *needs* with economic *wants*;

• The assumption that the mere addition of transmission will improve grid reliability. It won't. In fact, more transmission can actually degrade reliability if it is used to accommodate higher power transfers over long distances;

• The misapplication of national reliability standards promulgated by the North American Electric Reliability Corp. (NERC), the organization designated by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) mandated by EPAct;

• Blackout "scare tactics" intended to frighten customers and public officials, compelling them to endorse the construction of facilities or implementation of policies which are not required to preserve or enhance reliability.

Because of the confusion between economics and reliability, officials often commingle both inappropriately. A prime example is the 2006 Congestion Study conducted by the Department of Energy (DOE), as mandated by EPAct. [An updated 2009 Congestion Study is now under way.] As a result of its 2006 study, which did not properly consider non-transmission alternatives, the Department designated certain National Interest Electric Transmission Corridors where, according to DOE, consumers were adversely affected by transmission congestion or constraints. But the DOE's failure to properly consider non-transmission alternatives means that the congestion study has not even established economic congestion. In addition, congestion or constraints do not equal low reliability. Neither the 2006 study, nor the corridor designations, bear any resemblance to actual reliability problems. Economic *wants* were misrepresented as reliability *needs*. Reliability depends on standards, not the ability to move every megawatt from any generator anywhere on the system to any load center anywhere else on the system. Because the 2006 Congestion Study is fatally flawed, and does not draw a proper distinction between reliability and economics, it should not be used as the basis for approving new transmission lines that have been denied by the states.

In the deregulated electric power industry, the cost of new bulk power transmission facilities is often "socialized" if it can be shown that these facilities are needed to maintain reliability – to satisfy NERC reliability standards. "Socialization" means that the cost will be proportionally distributed among all customers within an Independent System Operator (ISO) or Regional Transmission Organization (RTO). If a reliability need cannot be proven, the cost will usually be assigned to those entities which will gain from the new facility. For example, if a new line is desired to allow the construction of new generating plants far removed from the load centers, and facilitate the transfer of their electrical output to the load centers, then clearly those generators will gain. But, if a reliability "need" could somehow be proven, the cost of the line would be borne by all customers in the region – an indirect but very real subsidy to the remote generators. Further, the skewing of costs and benefits would penalize resources located close to the load centers. It would also encourage the development of remote generating resources and discourage the development of more local or distributed generation, or demand side management programs.

The following points are generalizations derived from actual cases presented over the past several years.

In order to "prove" a reliability "need," some have misrepresented and misapplied the national reliability standards promulgated by NERC and supported by FERC. This misrepresentation sometimes involves ignoring key provisions of a national standard. For example, one of the key NERC planning standards calls for testing the system for the outage of a critical facility, allowing time for manual system readjustments to compensate for the outage, and then applying a second critical outage. The system must be designed to survive this sequence of events. However, some parties seem to have deliberately ignored the provision for manual system adjustments. This has the effect of greatly overstating the adverse consequences of the contingencies, in effect subjecting the system to two simultaneous contingencies. This, in turn, can indicate a failure to meet reliability standards – requiring a transmission reinforcement which is not really needed.

An even simpler example is the manipulation of generating units in the ISO or RTO queue in such a way that some committed units are excluded from planning studies. In some cases, units well along in the process have been deliberately excluded from studies because they would solve a reliability problem, while others *at the same place in the queue* were included, precisely because they exacerbate a reliability problem. In my opinion, this makes absolutely no sense.

Similarly, some have ignored readily available techniques permitted by the standards and widely utilized throughout the industry. They resist simple, straightforward fixes such as the addition of reactive power support, correction of minor limitations on lower voltage facilities, modification of outdated configurations, redispatch of generation, or manual load shedding following a contingency – all of which are permitted by the NERC standards and widely used in the industry.

Another device used by some to allege a reliability need when none really exists is to base system simulation studies on extreme conditions vis-à-vis generation dispatch. They will stubbornly insist on economic dispatch as a kind of mantra, ignoring the simple expedient of transmission constrained dispatch – using "out of merit" generation – to essentially replace less expensive remote generation with generation or demand side resources closer to the load, in effect working around any alleged transmission bottleneck by replacing remote generation with slightly higher-priced local resources. Many U.S. systems routinely operate in this manner. But some who are intent on "proving" a reliability need in their planning studies will refuse to make even minor adjustments to their initial dispatch in order to solve apparent reliability problems.

Those who misapply the reliability standards will often argue that NERC standards *require* that each ISO, RTO and transmission owner establish procedures that "stress" the transmission system in its planning studies. That's correct. But NERC standards do *not* require that the ISOs, RTOs and transmission owners use unrealistic base conditions, dismiss simple and obvious solutions to reliability problems, or ignore important provisions of the standards like manual system adjustments.

Some will maintain that the addition of new transmission facilities alone will inevitably increase reliability. This seems like common sense – but it's wrong. Addition of new transmission facilities will increase transfer capability, but reliability can only be improved by making the standards themselves more stringent. *Reliability is a function of the standards used, not the amount of wire in the air*. Further, transmission additions will not increase the reliability of the system if the increased transfer capability is used to accommodate increased power transfers. The same reliability standards would still be in place. The transmission transfer capabilities would be higher, but the higher transfer capability would simply be used to carry higher long-distance power flows.

There's another factor to consider. If more generation is built in remote areas, and less generation and other resources are built close to load centers, then the load centers will be increasingly dependent on distant generating capacity – located perhaps hundreds of miles away. It would be like running a long extension cord to a friend's house a block or two away to power your toaster, instead of plugging it into an electric outlet right in your own kitchen. The more major cities depend on long transmission lines, the more subject they will be to power outages and blackouts due to major contingencies on the transmission system. Indeed, this constitutes a national security problem, since these urban areas would be more at risk from terrorist attacks on transmission facilities.

Unfortunately, a lot of scare tactics have been used to justify proposed transmission lines. Perhaps the most egregious strategy used by those promoting new transmission when it really isn't needed for reliability involves raising the spectre of massive blackouts. The August 14, 2003 blackout has often been cited, for example. Even the California rotating blackouts of the 2000-2001 period have been mentioned. These incidents have *no bearing* on any of the cases I've seen. The 2003 blackout was the result of too many control areas (now known as "balancing authorities") in too small a geoelectrical area – so small, in fact, that none of them realized that a series of unrelated contingencies across a wide area over a four hour period was leading to a major interruption. In California in 2000-2001, poor state regulations, unscrupulous market manipulation, and unethical (sometimes illegal) activities by companies like Enron, all combined to manufacture an apparent shortage of generating capacity. No capacity shortage existed – nor was there a "blackout" *per se*. Brownouts and rotating feeder outages were necessary because of the market manipulation, but no widespread cascading outages occurred.

Let's think about how real-life systems would deal with situations involving overloaded transmission. System operators in real-time control centers act as balancing authorities over large geoelectrical areas, and would recognize any potential overload situation. More important, they would never operate the system in a mode where a first contingency would bring about overloads, low voltages, cascading outages, instability, system separation, or loss of firm customer load. That's the "Prime Directive" of every system operator. The bulk power system must always be operated such that, if any contingency specified in the applicable standards or criteria were to occur (e.g., a fault or short-circuit on a high voltage transmission line), the system would experience no overloads, low voltages, cascading outages, instability, system separations, or loss of firm customer load. In fact, to operate in any other way would be a violation or NERC's Operating Standards, subject to fines of up to $1 million per day.

Blackouts are usually caused by contingencies more severe than standards/criteria, by equipment failures, control system problems, human error, or by some combination of these. They always involve a break-up of the bulk power transmission system. Blackouts are not caused by shortages of generating capacity. Nor are they caused by an inability to transfer as much power as some might wish from remote locations to load centers. Blackouts can rarely be anticipated. They are almost always unexpected, and can happen at any time – few have occurred at or near peak load, for example, or coincident with a shortage of generating capacity. They develop in seconds or fractions of seconds rather than hours or days.

There's another important point. <u>The mere fact of adding transmission does not of itself increase reliability</u>. Consider two hypothetical transmission systems: one a system with a lot of transmission lines, but planned and operated to <u>less</u> stringent reliability standards; the other a system with very little transmission, but planned and operated to <u>more</u> stringent reliability standards. The first system would be less reliable than the second system, because it uses less stringent reliability standards. As I said earlier: *Reliability is a function of the standards used, not the amount of wire in the air*.

Even if both systems were planned and operated to the same reliability standards, the system with more transmission lines might still be less reliable than one with less. This is because the addition of new transmission lowers the equivalent electrical impedance across the grid, in effect making it electrically smaller. Thus a given contingency could have a more widespread effect. For example, if Philadelphia is electrically closer to Chicago, a major disturbance on the grid in the Chicago area is more likely to cause outages in Philadelphia – and *vice versa*. This may help explain why the Aug. 14, 2003 blackout affected a much larger area than the November 9, 1965 blackout.

Again, transmission additions will not increase the reliability of a system when the increased transfer capability is used to accommodate increased power transfers between remote generating units and load centers.

To ensure reliability of the bulk power system, Congress would need to comprehensively address electric power supply issues. Congress would need to encourage local power generation and distributed generation close to the demand, and create incentives for conservation and demand side resources. Any consideration of transmission issues should make a clear distinction between facilities needed for reliability and those desired for economic reasons. In particular, *economic wants* should not be permitted to camouflage themselves as *reliability needs*. Such an approach would help avoid blackouts, and make our grids less vulnerable to terrorist attacks.

However, as set forth above, I believe the states and the eight existing regional reliability councils are in the best position to ensure a reliable electrical grid.

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These are my major points. I would also like to briefly enumerate a few other problems I see, either on the horizon or already with us:

• The "deregulation" or "restructuring" of the electric power industry is part of the problem. In essence, it greatly increased the complexity of the power industry, and added thousands of pages of new regulations. (As a matter of fact, even the term "deregulation" itself is an Orwellian misstatement.) Most important, though, it replaced the former culture of *coordination and cooperation* with one of *competition and confrontation*.

• In some parts of the country, there are what I would term "overlapping footprints" among the various entities involved in the planning and operation of both the physical power system itself and its markets. This overlapping is a prescription for blackouts.

• Some control areas, or balancing authorities, are too small. As mentioned earlier, this was arguably the underlying cause of the August 14, 2003 blackout.

• The present growth rate of electric power demand and consumption is sometimes identified as the culprit. Actually, there's nothing exceptional about present growth rates. The *NERC 2006 Long-Term Reliability Assessment (October 2006)* reported a forecast U.S. annual growth rate for the period 2006-2015 of 1.9%. This is quite low by historical standards – for example, in the early 1960s, when I began my career, peak loads were growing nationally at a 7 to 7½% rate. That wasn't a short-term phenomenon, either. According to U.S. Energy Information Administration statistics, retail sales of electricity in 1970 were *five times higher* than in 1950 – a compound annual growth rate in excess of 7%. It doubled again between 1970 and 1990 – approximately a 3% growth rate – despite oil embargoes, hyper-inflation, recession, and conservation efforts. The only thing unusual about today's growth rate is that it's so low. This, I believe, reflects the efforts of many people – dedicated environmentalists, government officials at both the federal and state level, large commercial and industrial customers, and the general public – to achieve higher efficiencies and genuine conservation. We can all take credit for this significant accomplishment. Bottom line: nothing about current growth rates automatically requires a massive program of new transmission construction.

• People are often told that one "silver bullet" or another will solve all of our energy problems. Examples range from capacity auctions to mandatory standards, from renewable resources to the so-called "smart grid." While some of these may be valuable in their own right, none can be, as St. Paul might say, "All things to all men." Simply put, there is no silver bullet.

• Technical expertise – or at least competent, objective technical input – has become almost totally absent in decision making. Decisions are most often made on the basis of economic principles, with little or no consideration (or even knowledge) of the scientific laws that govern electric power systems. The Laws of Physics make electricity flow, not the Laws of Economics. No rules, no regulations or procedures, and no market protocols, can override Mother Nature and her laws. As I tell the students who take one of my courses or workshops: *When the Laws of Physics and the Laws of Economics collide, Physics wins … always*.

Where should we go from here? Frankly, I believe EPAct is in need of an overhaul. Congress needs to address energy issues – even those energy issues focused on electric power supply – in a more comprehensive manner. At present, EPAct encourages the siting of new transmission not needed for reliability. By doing so, it subsidizes remote generators, discriminates against local and distributed generation and demand side resources, forces many customers to pay for someone else's benefits, increases the likelihood of blackouts, and makes our grids more vulnerable to terrorist attack.

I would like to conclude with a favorite and well-known quote from the 18th Century Anglo-Irish author, philosopher and politician, Edmund Burke: "All that is necessary for the triumph of evil is for good men to do nothing." Let's resolve *not* to "do nothing," but let's be sure that, whatever we do, we do the *right* thing.

George C. Loehr – July 2008

George C. Loehr

[bio]

George C. Loehr received a Bachelor of Electrical Engineering degree from Manhattan College in 1962, and a Master of Arts in English Literature from New York University in 1964. He began his engineering career in transmission planning with the Consolidated Edison Company of New York in 1962, and completed the GE Power Systems Engineering Course in 1965. Following the 1965 Northeast Blackout, he was actively involved in a wide range of follow-up activities, and chaired the committee which completed a computer simulation of the event – the first such successful simulation of a wide-spread power failure in North America.

Loehr joined the New York Power Authority as Chief Planning Engineer in 1969, and the Northeast Power Coordinating Council (NPCC) in 1972. He was very active in regional, national and North American Electric Reliability Council (NERC) activities, serving on numerous committees, subcommittees and task forces. He was named Executive Director of NPCC in 1989, and remained in that position until his retirement in 1997.

Now self-employed, Mr. Loehr does management consulting, appears as an expert witness, writes, and teaches a variety of courses on power systems to non-technical professionals. His clients have included organizations throughout the U.S., Canada and China. He has served as Vice President and member of the Board of Directors of the American Education Institute (AEI), and is a charter member of Power Engineers Supporting Truth (PEST). Loehr is presently Chair and an Unaffiliated Member of the Executive Committee of the New York State Reliability Council, which works in conjunction with the New York ISO, and previously chaired its Reliability Compliance Monitoring Subcommittee. He also serves as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC). He is a recognized national expert on electric power system reliability.

Mr. Loehr has given expert testimony in the states of Pennsylvania, New York, Vermont, Kentucky, New Mexico, Mississippi, and in Washington, DC. He has done TV interviews with BBC, CNN, WPIX and CBC, and has been a lecturer, keynote speaker, and/or chair at professional conferences all over the U.S. and Canada. In addition, he has done audio tape lectures for various organizations, including the IEEE, "Professional Development Options," "Red Vector," and AEI.

Articles by Mr. Loehr have appeared widely in the trade press, including *Public Utilities Fortnightly, Electrical World, The Electricity Journal, Electricity Daily, Transmission & Distribution World, Energy Perspective, Restructuring Today, Energy Pulse, Natural Gas & Electricity, EnergyBiz,* and the Belgian magazine, *Revue E tijdschrift*. A recent op-ed piece was published in *The New York Times*. He is co-editor of and a contributor to the IEEE book, *The Evolution of Electric Power Transmission Under Deregulation*.

In addition to his engineering career, Mr. Loehr is a published author, has exhibited his art photographs at galleries in the New York metropolitan area, and has done stock photography for a world-wide photo agency. His photographs have appeared in numerous magazines, advertisements, business brochures, and several "coffee table" books, and one of his art photos was used as the cover for Sandra Brown's best-selling novel, *Fat Tuesday*. He recently published his own first novel, *Blackout*.

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April 25, 2025

Will Seuffert
Executive Secretary
Public Utilities Commission
121 – 7th Place East, #350
St. Paul, MN 55101

eFiled and email: consumer.puc@state.mn.us

RE: "NEED" Reply Comment
The Prehn Family & NoCapX 2020
Mankato-Mississippi River Transmission Line f/k/a Wilmarth-N Rochester-Tremval
PUC Certificate of Need Docket CN-22-532

Dear Mr. Seuffert:

Thank you for the opportunity to file this Reply Comment, made on behalf of the Prehn Family and NoCapX 2020.

As stated in our Initial Comment, claims of transmission need is misinformation at best. The issue in transmission is that transmission is not where it is wanted. There's sufficient generation, and that generation has been sited away from load where there is not sufficient transmission to interconnect, and sited where projects are waiting years and years to interconnect. The siting of all this generation far from transmission, far from load, and the following claim that transmission is "needed," falls on the applicants and on the Public Utilities Commission for permitting these projects. This is a systemic problem. It is unreasonable to require ratepayers and landowners to pay for this transmission, and doubly unfair when the proposed transmission is not to serve Minnesotans, but to enable MISO's marketing plan.

For years, decades really, this writer has been representing intervenors raising the essential truth that need is not a matter of utility and industry desires; that it is the distribution system that needs beefing up and that utilities are proffering transmission "solutions" to distribution deficiencies; and more recently, that MISO "approval" is not a demonstration of need – MISO is a marketing entity, and "benefits" of transmission it proposes are benefits to MISO members.[1] Most importantly in terms of this and other Certificate of Need dockets, the Commission abdicates its responsibility to ratepayers and the public when it accepts a MISO approval as need, rather than give the project a robust Minnesota oriented independent review, and instead permits billions in utility marketing desire and subsequent transmission costs that are foisted on ratepayers and landowners.

I. USE OF "INFORMAL" PROCESS IS EXAMPLE OF ABDICATION OF REGULATORY POWER AND LIMITS TO PUBLIC PARTICIPATION

In this Reply comment, the first item on the agenda is that when Initial Comments were filed in this "informal" process, there were filings by only **FIVE** entities – the Applicant Xcel, MISO, Commerce DER, "Joint Commenters" and NoCapX 2020 and the Prehn Family. All but NoCapX and the Prehn Family are "funded," with staff working on a payroll and weighing in on Commission dockets. That's significant, as the public has limited funding options, which limits participation. The 2024 legislature passed significant broadening of Commission dockets eligible for applications for intervenor compensation, including most dockets under Minn. Stat. ch. 216B, with the notable exception of Certificate of Need dockets, and of course, no provision for intervenor compensation for those participating/intervening in transmission line or siting dockets. See **Minn. Stat. §216B.631**.

The Commission's use of the "informal" process rather than a contested cases, where the record is based on the Application, agency review, and only written Initial and Reply Comments such as this, is an example of passive abdication of regulatory power. The "informal" process also inherently limits participation by the public, which is already at a disadvantage due to the state's bifurcated process and failure to convey the purpose and opportunity of a Certificate of Need proceeding at public meetings/hearings focused on the transmission line routing. As above, only five CoN Initial Comments were filed, and all but NoCapX and the Prehn Family support the project!

> With the exception of the Prehn family and NoCapX 2020, all commenters agreed with the Applicant's request for the CN application to be reviewed under the informal review process in Minn. R. 7829.1200. Reasons cited for using the informal review process included: the need to expedite review and approval of the project to prevent reliability issues for the projected future transmission system; the need to provide opportunities for efficient use of intervenors' limited resources in cases without substantive disputes; and sufficient opportunities in the informal process to provide for environmental evaluation, a public hearing, and written comments. The Prehn family and NoCapX 2020 requested referral of the CN application to the Office of Administrative Hearings (OAH) for a contested case hearing. Citing the high voltage and significant length of the Project, they argue that contested issues of fact will emerge throughout the Project review process. They did not include any issues of fact that they specifically argued are contested at this time.

Commission Order, June 26, 2024, p. 4.

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[1] See e.g., Attachment C, Testimony of George C. Loehr in the PATH docket, addressing some of the issues present in this and all other utilities' MISO Tranche 1 and 2 transmission applications, in particular the reliability advantages of distributed generation, the inherent instability of high voltage transmission over long distances, etc..

Under the Commission's Order for the "informal process" for this Certificate of Need docket, contested issues and record development is deemed for the transmission line routing docket!

> Additionally, the Commission will authorize the CN proceedings to follow the informal review process permitted in Minn. R. 7829.1200. This process is sufficient to allow for robust public participation and record development, and no contested issues of fact have been identified that would require a contested case on this matter in addition to the processes required under the full permitting process of Minn. Stat. § 216E.03 and Minn. R. 7850.1700 to 2700.

Id., p. 5. The Commission also Ordered many Exemptions for Xcel in this Order.

The rules do limit the projects qualifying for informal review, with direction for "Presentation of facts" for the record:

> **7829.1200 INFORMAL OR EXPEDITED PROCEEDING.**
>
> Subpart 1. **When appropriate.** Informal or expedited proceedings may be used when contested case proceedings are not required, for example, when:
>
> A. there are no material facts in dispute;
>
> B. the parties and the commission have agreed to informal or expedited proceedings; or
>
> C. informal or expedited proceedings are authorized or required by statute.
>
> Subp. 2. **Presentation of facts.** Written submissions are the preferred method of introducing facts. The commission shall allow oral presentation of facts when that can be done without compromising the rights of any person or the integrity of the proceeding. In informal proceedings, the commission shall require that factual allegations be made under oath or by affirmation when facts appear to be in dispute. In expedited proceedings, the commission shall require that factual allegations be made under oath or by affirmation and that documents filed in the proceeding be verified.

Minn. R. 7829.1200.

Comments filed in this docket are not made under oath, and in meetings, those commenting are not sworn in, even if they are commenting on "need" in addition to commenting on the transmission line route.[2] This is inconsistent with the rule. There is also no way for the public to question, under oath, the applicant and other parties/participants.

Many members of the public have weighed in on the transmission side of this project, TL-23-157, as their land, their communities, are affected, and yet in the public meetings and hearings, they are not provided with sufficient information about the Certificate of Need docket, intervention, the opportunities for participation even as a participant, and are not informed of the meaning of a Need determination and necessity that "need" precede routing of a transmission line. These issues have been repeatedly been raised at Annual Power Plant Siting Act Hearings. See **Minn. Stat. §216I.15**

The Commission should take an active role in informing the public of participation options, and should not utilize this informal process when a large project, in voltage, in miles, and in importance, is at issue.

[2] This writer has participated in meetings and hearings where, when asked to be sworn in, the ALJ has refused!

II. MISO IS NOT THE DECIDER, MISO IS NOT THE REGULATOR[3]

The Minnesota Public Utilities Commission is, obviously, the statutorily mandated regulator of Minnesota's Public Utilities. However, the Initial Comments of MISO and the Initial Comments of applicant Xcel focus on the **entirety** of MISO Tranche 1, and LRPT 4 as a part of Tranche 1, and the Mankato-Mississippi River project as a part of LRPT 4 – all referring to MISO's "approval" of the **entire** Tranche 1 as justification of need for the project:

> *As an overview to my comments, the Mankato-Mississippi River Transmission Project will help ensure the ability of the transmission system to meet challenges presented by the on-going and projected transition of generation resources and the need for development of long-term transmission planning solutions. The Mankato-Mississippi River Transmission Project will help realize the benefits identified by MISO and* ***stakeholder review*** *of the Long Range Transmission Planning ("LRTP") Tranche 1 portfolio of projects that were approved by MISO as an important part of the MISO Transmission Expansion Plan ("MTEP"). The MISO analyses of the existing transmission system during the MTEP21 planning cycle identified numerous transmission facilities that will be loaded above safe operating levels or below adequate voltage levels without the Mankato-Mississippi River Transmission Project. The overall system would also be more secure with the addition of the Project, which addresses additional voltage and transient stability limitations. Without the Mankato~~-~~Mississippi River Transmission Project, Minnesota and other states in the MISO footprint would not receive the full set of economic benefits that are provided by the LRTP Tranche 1 portfolio.*

MISO Initial Comment, p. 1 (emphasis added). As shown in this "overview," it's all about MISO.

> *The purpose of these comments is to generally describe the planning functions performed by MISO, including the development of MTEP.*

MISO Initial Comment, p. 3.

The entire MISO Initial Comment is about MISO, not surprisingly, but MISO is not the applicant, and its case highlights corporate self-interest of MISO and its members, in which the public has no part. Starting on page 2:

- **Background** – about the writer and MISO
- **Purpose and Scope of These Comments** – describe planning functions performed by MISO
- **MISO Regional Transmission Planning** – self-explanatory
- **Long Range Transmission Planning Process** - the MISO LRTP process
- **Reliability Planning Considerations** – MISO reliability analysis

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[3] NoCapX and the Prehn Family seem to have struck a nerve with the assertion that "MISO IS NOT THE REGLATOR" evidenced by the **MISO Reply Comment,** just received -- 13 pages single spaced in response to only the Initial Comment of NoCapX 2020 and the Prehn Family. These 13 pages are a demonstration of the relevance of comments made. Recent emails sent by MISO counsel show reluctance to let filings about relevant umbrella issues surface. See Attachment A, Recent email thread between Small & Overland.

- **Reliability and Project Justification** – powerflow simulations (let's see powerflows so we know where the power actually flows, i.e., Chester alternative, Xcel Initial Comment p. 7)
- **Economic and Public Policy Considerations** – LRPT Tranche 1 portfolio justification
- **Regional Impacts and Policies** – LRTP Tranche 1 project cost recovery

Xcel's Initial Comment is much the same in its MISO focus and claimed benefits:

> *The Project was studied, reviewed, and approved as part of the Long-Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO) Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report.1 The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as a portion of LRTP42 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio. The transmission system in southern Minnesota is the nexus between significant renewable resources in Minnesota and the Dakotas and the regional load center of the Twin Cities and load centers to the east in Wisconsin. The amount of renewable energy generation on the electric system is increasing as aging traditional generation resources retire and are replaced with renewable resources. This Project will provide additional transmission capacity that is needed to reliably deliver this renewable energy to customers. This Project will relieve overloads on existing transmission facilities and will reduce congestion on the transmission system, resulting in lower energy costs. This Project will also help make significant progress towards Minnesota's carbon emission reduction policy objectives.*

Xcel Initial Comment, p. 1-2.

The same is applicable to the "Joint Commenters" filing. The footnotes repeatedly cite the Xcel Application, MTEP21 Portfolio, LRPT Tranche 1 Portfolio Detailed **Business Case**, and the comments rely on MISO's "approval," and Xcel's application.

MISO Tranche 1 covers a lot of ground, of which this line is part of project "4" from Wilmarth to North Rochester to Tremval, this part known as Mankato to Mississippi River:

Map 4-2
MISO LRTP Tranche 1 Portfolio

Xcel Application, p. 57.

The big picture, recent history, is that MISO "approved" the $10.4 Billion Tranche 1 portfolio of transmission projects on July 22, 2022, following MISO's 17 MVP Portfolio[4] projects, with numbers 3, 4 and 5 in southern Minnesota, northern Iowa, and western Wisconsin, which followed CapX 2020's 700+ miles and $2 billion in transmission all over Minnesota. MISO is now in the process of "approving" the $22 Billion, 24 project, Tranche 2.1, which is planning on an unprecedented web of 765kV transmission across the Midwest, including projects 22, 24, 25 and 26 765kV lines, which are also criss-crossing southern Minnesota in the area of, often parallelling, CapX, MVP, and Tranche 1 transmission. Commerce-DER discusses 765kV option without reference to the MISO Tranche 2.1 waiting in the wings. Commerce-DER, p. 15.

How much transmission could we possibly "need?" CapX 2020 $2+ billion, MVP 2011 of $6.5 billion, plus Tranche 1 $10.4 billion plus Tranche 2.1 $22 billion is an extreme outlay for transmission. The utilities' reliance on, and Public Utilities Commission acceptance and apparent acquiescence, to MISO "approval" is misplaced where the cost is so extreme and transmission is the only option "studied."

The Commission is the regulator, and is responsible for setting rates, and through permitting, is also responsible for inflicting eminent domain on landowners. The Commission owes Minnesotans higher scrutiny than is now afforded these projects through its reliance on MISO "approval.".

III. REGIONAL PLANS OF INDEPENDENT SYSTEM OPERATORS MUST NOT PREEMPT A STATE'S REGULATORY PERMITTING PROCESS AND POWER

As above, MISO is not the regulator. A transmission applicant's interest, an Independent Service Operator's Interest is not the same as, and is often in conflict with, the public interest. It's the state's job in a permitting proceeding to consider the public interest, and to weigh the public interest with the private corporate interest of an applicant and an ISO.

In Xcel's Application, its Initial Need Comments, in MISO's Procedure and Initial Need Comments, and in the "Joint Commenters" the focus is on the LRPT Tranche 1 regional plan. A Reply to Initial Comments can't ignore this focus on MISO and MISO approval as justification for this and other projects.

Regional plans of Independent System Operators must not directly or indirectly preempt a state's regulatory permitting process and power. Where a utility and an Independent System Operator use a regional plan as the basis for a claim of need in a state application for a project as is done in this docket, and where a Commission's relies on the proffering of that regional plan as demonstration of need, the precedence of acceptance and apparent acquiescence is a step towards de facto preemption of the state's regulatory power. This is particularly possible, perhaps probably, in a need docket utilizing this "informal" process. The Commission should not put

[4] See Ex.-MISO-Rauch-1, Multi Value Project Portfolio Results and Analyses, January 10, 2012, EXHIBIT 1 TO DIRECT TESTIMONY OF LAURA RAUCH, Submitted on Behalf of MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. (MISO), September 15, 2014, PUBLIC SERVICE COMMISSION OF WISCONSIN, DOCKET NO. 5-CE-142: https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=218120

itself in a “use it or lose it” situation that establishes precedence for this “review light.”. A recent FERC Order[5] rejected PJM’s request to allow an extension of the deadline for completing its annual market efficiency reevaluation for the Transource Independence Energy Connection Project (Transource IEC Project) as moot – the Commission expressly did not address the substance of PJM’s request. Attachment B, FERC Order Dismissing Waiver Request and Concurrence, April 17, 2025.

Of note is the Chair’s Concurrence, focused on the big picture which is relevant in this proceeding – the notion of an “Independent System Operator’s” pre-emption of a state’s regulatory authority, in this case, an overt direct claim by PJM:

> In December 2023, I wrote a concurrence to a seemingly routine letter order closing the long running PATH transmission project.**1** [citing *See Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (2023) (Christie, Comm’r, concurring), https://cms.ferc.gov/news-events/news/e-4-commissioner-christies-concurrence-letter-order-approving-path-settlement-er12.] That was the transmission project for which consumers in PJM paid approximately a quarter billion dollars without a single state ever approving a certificate of public convenience and necessity (CPCN), nor a single ounce of steel ever going into the ground. I said in that concurrence that the letter order may not seem noteworthy, but “. . . as Willy Loman’s wife said in *Death of a Salesman,* ‘attention *must be paid*.’”**2** [*Id.* P 1 (emphasis in original).] As the debate continues over whether to grant to transmission owners who joined PJM or other RTOs/ISOs a *perpetual* adder of 50 or more basis points to their return on equity (profit) – which flows right into hard-pressed consumers’ power bills – attention must be paid to this seemingly routine order as well.
> …
> In their federal court filings, PJM and Transource argue that the mere fact that PJM planned a project that was put into the PJM regional transmission plan (RTEP) was an act sufficient to pre-empt a state’s sovereign police power authority to conduct a CPCN proceeding and to determine whether the project was needed to serve its own consumers.**4 [***See, e.g.*, Brief of Appellee Transource Pennsylvania, LLC. (Transource Third Circuit Brief) at 3-7 and *passim*, Steven DeFrank, et al., v. Transource Pennsylvania, LLC., No. 24-1045 (3d Cir. July 10, 2024); Brief for Amicus Curiae PJM Interconnection, L.L.C. Supporting Appellee [Transource] and Supporting Affirmance at 2-3 and *passim*, Steven DeFrank, et al., v. Transource Pennsylvania, LLC., No. 24-1045 (3d Cir. July 17, 2024).] After all, *Pennsylvania consumers will pay* for the project under PJM’s cost allocation formula.
>
> The claim that, because PJM and other RTOs are federally regulated, the inclusion of a PJM-planned transmission project in PJM’s RTEP effectively pre-empts a state’s inherent police power authority to approve that and other utility projects within its borders is, frankly, outrageous. FERC Order No. 1000, which

[5] See Attachment B, FERC Order Dismissing Waiver Request, and Chair Christie’s Concurrence, FERC Docket No. ER25-612-000.

> set up the entire regional planning regime under which PJM and other RTOs now operate, said the opposite.**5** [*See, e.g.*, *Transmission Plan. & Cost Allocation by Transmission Owning &Operating Pub. Utils*., Order No. 1000, 136 FERC ¶ 61,051, at PP 227, 253 n.231, 287 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 342, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).]
>
> …
>
> Today both Transource Pennsylvania, majority owned by AEP, and PJM, are arguing in federal court that the Commonwealth of Pennsylvania – and by logical extension *all states including the Commonwealth of Virginia* – are *pre-empted* from exercising their CPCN laws to approve – or reject – a project once that project has been planned by PJM for its regional plan. Should AEP and PJM succeed in persuading a federal court that the mere selection of a transmission project planned by PJM acts to pre-empt the states' CPCN laws – a position vigorously opposed by all the states as expressed by the National Association of Regulatory State Commissioners (NARUC)**11** – such a ruling will likely be a Pyrrhic victory of monumental proportions. Such an outcome will tell the states, which retain the authority under their inherent police powers to decide whether to allow their utilities to join, not join, or leave RTOs, that the rules of the game have been changed radically after the fact – without the states' agreement and, as the history recounted herein shows, *contrary to earlier pledges to respect state laws.* So perhaps state perspectives on RTO membership for their utilities should be reconsidered.

Id., Concurrence, pps. 1-5; see also *Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (2023) (Christie, Comm'r, concurring at PP 2-3)[6], noting "For policy-driven long-distance, regional transmission projects affecting consumers in multiple states, it is absolutely essential that state regulators have the authority to approve – or disapprove – the construction of these lines *and* how they are selected for regional cost allocation *and* what that cost allocation formula is, if their consumers are going to be hit with the costs."

Pre-emption may be direct as PJM's argument, but pre-emption can also be insidious, where a need claim is entirely focused on the ISO wants and desires, where the purpose of the ISO is adopted by the regulator as a legitimate purpose and any and all alternatives proposed are measured for a fit with the ISO and applicant's purpose. As a regulator, it's the job of the Commission to measure the ISO and applicant's purpose for a fit with public purpose.

In our Initial Comment, NoCapX 2020 and the Prehn Family noted "MISO "approval" is not a demonstration of need – MISO is a marketing entity, and "benefits" of transmission it proposes are benefits to MISO members.[7] Where there is a "regional plan," it is vitally important to fully

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[6] Online: https://cms.ferc.gov/newsevents/news/e-4-commissioner-christies-concurrence-letter-order-approving-pathsettlement-er12,

[7] See e.g., Attachment C, Testimony of George C. Loehr in the Virginia PATH docket,PUE-2009-00043 addressing the big picture policy issues present in CapX 2020 projects, the MVP Portfolio projects, this MISO Tranche 1 and

identify what a proposed project does for the state and those ratepayers and landowners footing the bill. In this LRPT Tranche 1 regional plan, the benefits are to members. MISO claims to have worked with stakeholders, but state ratepayers and landowners are not among "stakeholders" participating in development of the plan. MISO Initial Comment, p. 9. "The purpose of the very extensive planning functions of MISO is to involve all **stakeholders**[8] in a process that will drive…" Id., p. 16 (emphasis added). Most importantly in terms of this and other Certificate of Need dockets, the Commission abdicates its responsibility to the excluded ratepayers and the public as it gives great weight to a MISO "approval" as a need demonstration, rather than give the project a robust Minnesota oriented independent review, and instead permits billions in utility marketing desire and subsequent transmission costs that are foisted on ratepayers and landowners.

Loehr's testimony before the U.S. Senate Energy and Natural Resources Committee on July 31, 2008, sets out the divergence of public interest and corporate interest, and conflation of these interests:

- The confusion of reliability with economics – of reliability *needs* with economic *wants*;
- The assumption that the mere addition of transmission will improve grid reliability. It won't. In fact, more transmission can actually degrade reliability if it is used to accommodate higher power transfers over long distances;
- The misapplication of national reliability standards promulgated by the North American Electric Reliability Corp. (NERC), the organization designated by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) mandated by EPAct;
- Blackout "scare tactics" intended to frighten customers and public officials, compelling them to endorse the construction of facilities or implementation of policies which are not required to preserve or enhance reliability.

Attachment D, Loehr Testimony before Senate Energy and Natural Resources Committee, July 31, 2008.[9] These points are lost in the rush to blanket the U.S. in transmission, bolstered by the economic wants of utilities and ISOs, FERC's rate of recovery permitted, and the revenue stream of bulk power transmission.

MISO's Independent Market Monitor raised similar big picture issues with the claims and characterizations in the Tranche 2 analysis, which despite MISO's objections, are applicable to Tranche 1, due to the consideration of so many factors with regulatory blinders on, focused

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all other utilities' MISO Tranche 1 and 2.1 transmission applications.

[8] "Stakeholders" is a very limited group. This writer has been prohibited from attending MISO planning meetings, ultimately obtaining at unreasonable trouble from MISO a letter from FERC confirming approval for access to CEII material. **MISO bars access to planning meetings** Posted on May 24, 2017. Thanks to reasonable minds at Minnesota Power and Great River Energy, I was able to get "confidential" information about the **"Northland Reliability Project," PUC Dockets CN-22-416 and TL-22-415**. Inappropriate branding of transmission information continues…

[9] Loehr Testimony also online at: online at: http://www.northbyram.org/routeb/pdf/loehr_testimony.pdf

solely on high-voltage transmission build-out over long distances from generation to large distant markets.

For MISO specific analysis of these "benefits" see Attachment E (previously Attachment B in NoCapX 2020 and the Prehn Family Initial Comment), MISO IMM Comments on LRTP Tranche 2 Benefit Metrics. This report bears repeating.

Again, MISO understandably finds the conclusions of this report objectionable, but these big picture comments point out the misinformation that serves as the basis for the MISO transmission build-outs, and the economic and reliability benefit of siting near load, which, if the corporate purpose of a project is accepted without scrutiny by regulators, is ignored. Per the MISO Independent Market Monitor filed during consideration of Tranche 2, and applicable to every transmission project:

- It is important that this investment be economic –
  - ✓ Uneconomic investment will raise costs and undermine investment in resources, storage and other alternatives to transmission.
  - ✓ We have previously expressed concerns about the unrealistic nature of Future 2A growth assumptions.
  - ✓ MISO has chosen not to attempt manual optimization (evaluating alternative siting impacts on individual projects or to resolve overloads).
  - ✓ The benefits methodologies are likely to lead to substantially over-estimated benefits, which we describe in this presentation.
- MISO has proposed 9 classes of transmission benefits.
- Classes that are likely to be valid and reasonable, depending on the details:
  - ✓ Congestion and fuel costs savings
  - ✓ Reduced transmission outage costs
- Classes for which we have significant or fundamental concerns:
  - ✓ Avoided capacity costs
  - ✓ Decarbonization
  - ✓ Mitigation of reliability issues
- Classes that are may be overestimated depending on the methodology
  - ✓ Capacity savings from reduced losses
  - ✓ Energy savings from reduced losses
  - ✓ Avoided transmission investments
  - ✓ Reduced risks from extreme weather events

Attachment E, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics.[10]

The Initial Comments of those in this docket reflect the acquiescence to MISO purpose and priorities and failure to address independent regulatory and public interest.

[10] Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics https://cdn.misoenergy.org/20240529%20LRTP%20Workshop%20Item%2002%20IMM%20Presentation633033.pdf

IV. MISO'S NEED CLAIM OF BOTH ECONOMIC AND RELIABILITY "BENEFITS" DO NOT AND CANNOT STAND ALONE FOR A SOLITARY PROJECT

This "North Mankato – North Rochester – Tremval" project does not exist in a vacuum. Its need claim, both economic and reliability "benefits," do not and cannot stand alone for a solitary project, and instead are dependent on construction and operation of all 18 Tranche 1 projects.

> *… without the Mankato-Mississippi River Transmission Project, Minnesota and the* ***other states in the MISO footprint*** *would not receive the full set of economic benefits that is provided by the* ***LRTP Tranche 1 portfolio****.*

MISO Initial Comment, p. 17, focused on Tranche 1, and not the Mankato-Mississippi River project..

The Mankato-Mississippi River project is repeatedly referred to as part of Tranche 1:

> *… as part of MISO's MTEP21 process. This approval was based on a set of reliability, economic, and public policy analyses conducted between 2020 and 2022 that documented the reliability benefits of the Mankato-Mississippi River Transmission Project and* ***the combined reliability, economic, and public policy benefits*** *of the LRTP Tranche 1 portfolio.*
>
> *…*
>
> *Tranche 1 provides a robust transmission network that supports a broad range of generation and policy futures. Support for the Mankato-Mississippi River Transmission Project,* ***as a planned part of LRTP Tranche 1 portfolio****, is described further in these comments…*

MISO Initial Comment, p. 4 (emphasis added). See also Xcel Initial Comment acknowledging that this project is but a part of a whole:

> *The Project was studied, reviewed, and approved as part of the Long-Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO) Board of Directors in July 2022 as a part of its 2021 Transmission Expansion Plan (MTEP21) Report. The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as a portion of LRTP42 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio.*

Xcel Initial Comment, p. 2, and in footnote 2, that "This Project is the Minnesota portion of LRTP4."[11]

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[11] "This project" is discussed in MISO and Xcel Initial Comments as the "Mankato-Mississippi River" project, but in the MTEP21 Report Addendum it's the ""Wilmarth-North Rochester-Tremval-Eau Claire-Jump River 345kV," a much larger project. Supra p. 4.

Xcel also states that the economic savings are "across the MISO footprint." Xcel Initial Comment, p. 3. Similarly, the "carbon reduction benefits" are credited to "implementation of the LRTP Tranche 1 Portfolio." Id.

The economic "benefits" claimed are dependent on the construction and operation of the entirety of the MISO Tranche 1 portfolio, and as above, "[w]ithout the Mankato-Mississippi River Transmission Project, Minnesota and other states in the MISO footprint would not receive the full set of economic benefits that are provided by the LRTP Tranche 1 portfolio." MISO Initial Comment, p. 1. Note MISO planning deficiencies in Commerce_DER Comment, p. 28-29.

MISO also claims "reliability benefits." MISO Initial Comment, p. 10-15. "In addition, the LRTP Tranche 1 portfolio as a whole mitigated overloading on 436 facilities including many severe overloads over 125 percent that could cause cascading or system instability, as documented in the MTEP21 Report Addendum.[18]" MISO Initial Comment, p. 13. However, footnote 18 states that "The figures summarize reports in tables that begin on p. 25." The tables on page 25 of the "MTEP21 Report Addendum[12]" are not for the Mankato-Mississippi River project. It is not until page 30, Figure 6-7 that the Mankato-Mississippi River is included, identified as a part of the much larger "Wilmarth-North Rochester-Tremval-**Eau Claire-Jump River** 345kV" project:

Projects:
Wilmarth – North Rochester – Tremval – Eau Claire – Jump River 345 kV
Tremval – Rocky Run – Columbia 345 kV

On this same page is the "Rationale" which explicitly characterizes the project as "transmission

[12] MTEP21 Addendum, p. 25. https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf

outlets to the East and South" and "strong flows West to East across Minnesota to Wisconsin…"

> **Rationale:**
> The transmission system in southern Minnesota is a nexus between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and transmission outlets to the East and South. In a future with significant renewable energy growth, MISO sees strong flows West to East across Minnesota to Wisconsin and a need for outlet for those renewables in times of high availability to deliver that energy to load centers in MISO. The Minnesota to Wisconsin projects relieve constraints in the Twin Cities metro area due to high renewable flow towards and past the Twin Cities load center. The projects also reinforce the outlet towards load centers in Wisconsin, providing relief of congestion as well as easing both thermal loading and transfer voltage stability.

What does this project do for Minnesota? As declared in the application, the Mankato-Mississippi River, a/k/a Wilmarth-North Rochester-Tremval, is the Minnesota portion of project 4 of MISO $10 billion Tranche 1:[13] And although the project is a part of the MISO Tranche 1, the Minnesota Public Utilities Commission is **MINNESOTA's** regulator and must address the "need," the public interest, and benefits and impacts to Minnesota.

V. XCEL'S QUESTIONABLE CLAIMS NEED FOR INCREASED CAPACITY

Xcel claims that the project is needed for increased capacity. Prove it!. Is it transmission capacity, or is it generation capacity, or is it a matter of generation sited in the wrong place, far away from available transmission? Project proponents claim:

- The Project is needed to address thermal overloads and congestion issues on the existing 345 kV system across southern Minnesota toward Wisconsin and will provide transmission outlets for renewable energy in Minnesota, North Dakota, and South Dakota. Xcel Initial Comment, p. 1.

- This Project will provide additional transmission capacity that is needed to reliably deliver this renewable energy to [utility] customers. This Project will relieve overloads on existing transmission facilities and will reduce congestion on the transmission system, resulting in lower energy costs [for?]. Id., p. 2.

- The Project provides significant reliability, economic, and carbon reduction benefits, and positions the Company to bring new renewable generation resources online in the coming years. As part of its analysis in MTEP21, MISO concluded that the LRTP4 project addresses overload issues along several transmission lines and at several transformers by providing additional capacity to the currently constrained transmission system in southern Minnesota. Id., p. 3

- [T]he LRTP4 project will also provide economic benefits to help offset its costs. Xcel Energy conducted additional economic analysis of LRTP4 and determined that it will provide up to $2.1 billion in economic savings across the MISO

[13] Id, p. 2

footprint over the first 20 years that the LRTP4 project is in service and up to $3.8 billion in economic savings across the MISO footprint over the first 40 years. Id..

On the other hand, Xcel's reliance in its Application and Initial Comments on MISO makes some sense, because where "need" is concerned, Xcel has a "need" problem. Despite the addition of much renewable generation, and planned and completed closure of coal plants, resulting in the freeing up of transmission capacity, Xcel's demand is flat. Demand has not yet met the 2006 peak of 9,859MW, calling "need" into question.

Again, this is worth repeating from our Initial Comment as demand is not mentioned in any party's Comment. From Xcel Energy's SEC 10-K filing[14], the peak of 2024:

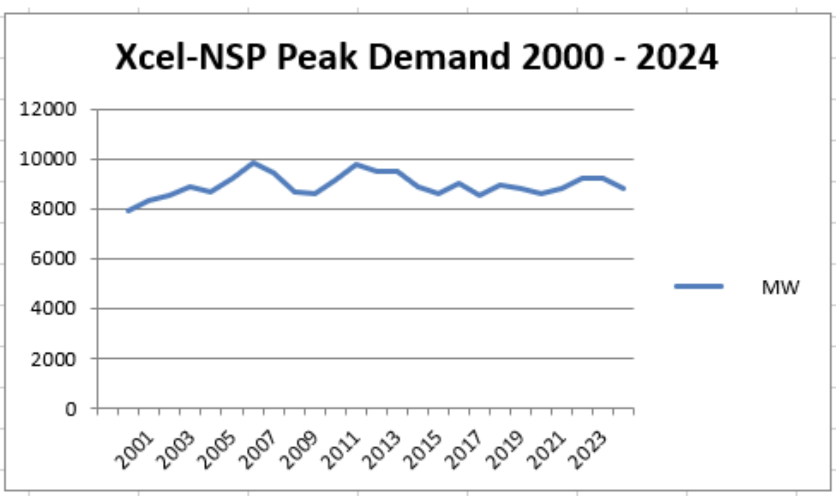
Capacity and Demand

Uninterrupted system peak demand and occurrence date:

	2024		2023	
Utility Subsidiary	**MW**	**Date**	**MW**	**Date**
NSP System	8,822	Aug. 26	9,231	Aug. 23
PSCo	7,084	Aug. 1	6,909	July 24
SPS	4,437	Aug. 19	4,372	Aug. 17

This is important because at 8,822 MW, Xcel's peak demand is down 409 MW from last year. How many AI data centers can operate on 409MW? More importantly, at 8,822 MW, Xcel's peak demand is 1,000MW shy of the all-time high peak demand of 9,859 MW in 2006! How many data centers can operate on that 1,000MW? Why is this important? Xcel is now crying that "demand will go UP, UP, UP!" 2.49% annually as it laughably claimed in the CapX 2005 Technical Report[15].

What does Peak Demand look like over the last 25 years according to Xcel Energy's SEC 10-K filings? Here are the numbers:



[14] Xcel's 2024 SEC 10-K: https://legalectric.org/f/2025/02/Xcel-Peak-Demand-2024_0000072903-25-000029-e2853810-9fe1-4df5-89d1-e14f11e5c841.pdf

[15] CapX 2020 Technical Update Identifying Minnesota's Electric Transmission Infrastructure Needs, May 2005, online at https://legalectric.org/f/2025/04/5-11-05-CapX2020-Tech-Update.pdf

From Xcel's 10-K SEC filings over the last 25 years:

2000	7,936
2001	8,344
2002	8,529
2003	8,868
2004	8,665
2005	9,212
2006	9,859
2007	9,477
2008	8,657
2009	8,615
2010	9,131
2011	9,792
2012	9,475
2013	9,524
2014	8,848
2015	8,621
2016	9,002
2017	8,546
2018	8,927
2019	8,774
2020	8,571
2021	8,857
2022	9,245
2023	9,231
2024	8,822

Xcel has met its need each year, and peak demand has been below the 2006 high, **in 2024, 1,000MW lower**, despite forecasted CapX 2020 "forecast" of 2.49% annual growth.[16]

VI. JOINT COMMENTORS CLAIM THIS PROJECT WILL REDUCE LINE LOSSES

The Joint Commentors, on page 6, claim that this project will reduce line losses:

> The Project will also reduce energy losses in Minnesota and throughout MISO, driving down generation costs for ratepayers.[27] As explained by the Applicant, energy losses must be factored in when determining how much generation is needed to serve system demand.[28] As energy losses decrease, so too does the amount of electricity needed to adequately serve customers, which is especially relevant during periods of demand growth.[29] As more load is added to the grid, reducing energy losses–and the associated generation requirements–will help offset the need for new generation facilities and improve overall system reliability.[30] The Project therefore bolsters the reliability of the regional grid and the adequacy of energy resources necessary to serve Minnesota's increasingly electrified economy.

[16] See CapX 2020 Technical Update, p. 5 (2005), Attachment E to CapX 2020 Certificate of Need Application. https://nocapx2020.info/wp-content/uploads/2012/02/capxvisionstudy20120214-515026913743.pdf

Line losses are an inherent byproduct of transmission, and longer lines means increased line losses. It's basic physics.

In this transmission application, Xcel includes tables regarding line loss. Xcel's 2006 peak demand of 9,859MW… that 9,000MW number seems familiar… oh, right, it's that chart of line losses, and MVAR losses of over 9,000MW in the <u>system</u> as it is, it's even more than Xcel's peak demand!

Table 4-15

Estimated Line Losses

MTEP22 2027 Shoulder High Wind Line Losses for LRZ1						
Model	**Base Model**	**LRTP 4**	**Delta**	**Tranche 1 without LRTP 4**	**Tranche 1**	**Delta**
MW Losses	1031.8	999.8	32.0	883.4	849.4	34.0
MVAR Losses	9628.6	9513.5	115.1	8882.3	8770.1	112.2

Future 1 Year 20 Shoulder High Wind Line Losses for LRZ1						
Model	**Base Model**	**LRTP 4**	**Delta**	**Tranche 1 without LRTP 4**	**Tranche 1**	**Delta**
MW Losses	1220.5	1159.6	60.9	1071.0	1027.0	44.0
MVAR Losses	10834.4	10490.2	344.2	9941.9	9782.6	159.3

One of the tropes of transmission build-out is that more transmission, and these high capacity transmission lines, would lower line loss! We've seen a lot of transmission built and operation, and look at the line loss. What amount of generation is necessary to make up for that line loss!

VII. <u>XCEL AND JOINT COMMENTERS TOUT CO2 REDUCTION BENEFITS, BUT HOW DOES TRANSMISSION LOWER CO2?</u>

In an odd conflation of physics, both Xcel and Joint Commentors claim that this project, or LRTP4, will reduce carbon emissions. From Xcel's Initial Comment, p. 3:

> Xcel Energy also analyzed the carbon reduction benefits of the LRTP4 project. MISO's analysis demonstrated the implementation of the LRTP Tranche 1 Portfolio is estimated to reduce carbon emissions by 399 million metric tons over the first 20 years and 677 million metric tons over the first 40 years that the LRTP Tranche 1 Portfolio is in service.[6] Xcel Energy estimated that the LRTP4 project will reduce carbon emissions by 197.9 million metric tons over the first 20 years that the LRTP4 project is in service and by 295.5 million metric tons over the first 40 years that the LRTP4 project is in service.[7]

The Joint Commentors make the same type of claim of reduced emissions:

> Air emissions associated with fossil fuel production and consumption include the greenhouse gas carbon dioxide as well as particulate matter, sulfur dioxide, nitrogen oxides, mercury, and other hazardous air pollutants.[66] The adverse environmental and health impacts of these hazardous pollutants will be incrementally alleviated as Minnesota transitions to clean energy resources that are not dependent on emissions-producing fuels. Between fostering new renewable energy developments and enabling fossil fuel plant retirements, the Applicant anticipates the Project will reduce emissions by 2.42 to 5.25 million metric tons over the first 20 years of operation.[67] Using the most conservative figure, this would be akin to avoiding the burning of 2.69 billion pounds of coal[68] or planting 40 million trees and letting them grow for ten years.[69]

Joint Commentors Initial Comment, p. 14; See also Commerce-DER p. 19.

Transmission is not a generator of emissions, other than electric and magnetic fields, and transmission cannot reduce emissions. Reduction of emissions only occurs with a reduction of burning. There is no reduction of burning with this project.

VIII. XCEL'S CHESTER JUNCTION SYSTEM ALTERNATIVE ECONOMIC ANALYSIS SHOULD BE CAREFULLY VETTED

In its Initial Comment, Xcel objects to the Chester Junction System Alternative. This Alternative was raised at the Pine Island hearing on July 9, 2024, Steve Hackman, of the North Route Group, an Intervenor with NoCapX 2020 in the CapX 2020 Hampton-La Crosse transmission project docket. Hackman offered specific system and route alternatives for the Chester 161kV line, which are included in Certificate of Need potential system alternatives.

Xcel's Initial Comment provides its analysis of the Chester Alternative in comparison to its own Chester plan, with some numbers that show that the project economics and benefits to the "project partners" outweigh the overall system benefits, and in the "second" analysis, Xcel utilized speculative and reverse engineering such that the inputs were changed to include the entire Tranche 2.1 buildout:

> *Xcel Energy performed a similar economic analyses on the Chester Junction Alternative using two sets of MISO models. The first round of analysis was performed using MISO'sMTEP21 Series 1A Future 2A model. This model assumes that all of the LRTP Tranche 1 Portfolio of projects are in-service but Xcel Energy modified this model to include either the LRTP4 project or the Chester Junction Alternative.* ***This first round of analysis showed that the Chester Junction Alternative provided $130.59 million in economic benefits to the MISO footprint*** *but provided* ***negative $2.85 million in economic benefits to the Project partners*** *(Xcel Energy, Southern Minnesota Municipal Power Agency (SMMPA), and Dairyland Power Cooperative (DPC)) for the first 20 years that the alternative is in service.*
>
> *In December 2024, MISO's Board of Directors approved its LRTP Tranche 2.1 Portfolio of projects. The LRTP Tranche 2.1 includes a number of new transmission projects in southern Minnesota. The second round of analysis performed by Xcel Energy used a more recent set of MISO models that assumed that all of the Tranche 2.1 transmission projects are in service. This second round of analysis compared the economic benefits of the Chester Junction Alternative to the proposed LRTP4* ***project once these MISO Tranche 2.1 projects are constructed.*** *Xcel Energy's economic analyses found* ***that the Chester Junction Alternative provided $14.95 million less in APC savings benefits to MISO Local Resource Zone 1 as compared to the proposed LRTP4 project*** *over the first 20-years that the alternative is in service. Similarly,* ***the Chester Junction Alternative has $15.48 million less in APC savings benefits to the Project partners*** *(Xcel Energy, Dairyland Power Cooperative, and SMMPA) as compared to the proposed LRTP4 project over the first 20 years that the alternative is in service.*

Xcel Initial Comment, p. 6 (emphasis added).

As a rationale to reject the Chester Junction Alternative, Xcel objects to a rebuild of three local 161kV transmission lines, the Crosstown – Cascade 161 kV transmission line; Crosstown – Silver Lake 161 kV transmission line; and Cascade to Bamber 161 kV transmission line due to overloads should the Byron-North Rochester 345kV fault. Id., p. 7.

Given the in-service date of the "Byron-North Rochester" transmission line, January 2, 1970, and lack of uprate/upgrade, and these 161kV lines that could overload, it seems that a rebuild of all of these existing transmission lines would be a wise, and overdue, investment rather than an excuse not to rebuild these lines to a higher capacity. See Attachment E, Xcel Response to NoCapX and the Prehn Family's IR 3 for in-service date of Prairie Island-Byron-Adams, with no uprate or upgrade since that time:

Table 1

	Prairie Island-Byron-Adams 345 kV			
First In Service Date	January 2, 1970			
Original rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	956.1	1192.1	1195.1	1195.1
Date of last uprate	N/A			
Description of upgrade	N/A			
Current rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	956.1	1192.1	1195.1	1195.1

Attachment 3 also contains Xcel's response to NoCapX and the Prehn Family's IR 2, regarding in-service date and uprates/upgrades to the King-Eau Claire-Arpin line:

Table 1

	King-Eau Claire-Arpin 345kV			
First In Service Date	January 1, 1960			
Original rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	1188.5	1188.5	1195.1	1195.1
Date of last uprate	N/A			
Description of upgrade	N/A			
Current rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	1191.5	1191.5	1195.1	1195.1

Id. Both of these 345kV lines are primary transmission for Minnesota export, Prairie Island-Byron to the south, and King-Eau Claire-Aprin to the east. Both are old lines that have not been rehabbed, not uprated or upgraded. As above, these lines are outdated, utilizing old an inefficient conductors, and are overdue for rehab.

This also brings to mind the classic question, “What happens if CapX 2020 goes down?” Beefing up the lower voltage system, the 161kV and the few 230kV lines, which Xcel has been doing with its 69kV to 115kV upgrades, is a logical preventative measure. Current planning for a 765kV overlay in Tranche 2.1 is just the opposite, it makes reliability an even greater concern – what happens when a line in the 765kV system is goes down?

IX. DISTRIBUTED GENERATION WAS REJECTED OUT OF HAND

MISO’s Initial Comment gives short shrift to distributed generation by presuming a regional build-out by focusing strictly on transmission development, expansion:

> *The LRTP Tranche 1 portfolio provides for a more cost-effective* ***regional build-out*** *of generation resources* ***rather than a greater amount of locally sited generation*** *that would be required without greater transmission development (i.e. due to local transmission limitations).*

MISO Initial Comment, p. 15 (emphasis added).

Loehr’s testimony before the U.S. Senate Energy Committee is on point:

> - The assumption that the mere addition of transmission will improve grid reliability. It won’t. In fact, more transmission can actually degrade reliability if it is used to accommodate higher power transfers over long distances;

Attachment D, Loehr U.D. Senate Energy Testimony.

And at this point, 1 p.m. on April 25, 2025, tempest is a fugiting…

Thank you for this opportunity to Comment on the Initial Comments in this docket.

Very truly yours,

Carol A Overland

Carol A. Overland
Attorney for the Prehn Family and NoCapX 2020

OAH 65-2500-40099
MPUC E-022/CN-22-532

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Xcel Energy for a Certificate of Need and Route Permit for the Mankato - Mississippi River 345 kV Transmission Line Project in Southeast Minnesota

---

NOCAPX 2020 AND THE PREHN FAMILY

CERTIFICATE OF SERVICE

I, Carol A. Overland, hereby certify that I have this day served a true and correct copy of the attached Prehn Family and NoCapX 2020 Reply Comment to all persons at the email addresses on the Public Utilities Commission eDockets service list by eFiling and eService.

April 25, 2025

Carol A. Overland

____

Carol A. Overland MN #254617
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overland@legalectric.org

OAH 65-2500-40099
MPUC E-022/CN-22-532

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
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In the Matter of the Application of Xcel Energy for a Certificate of Need and Route Permit for the Mankato - Mississippi River 345 kV Transmission Line Project in Southeast Minnesota

---

NOCAPX 2020 AND THE PREHN FAMILY

ATTACHMENTS TO REPLY COMMENTS

Attachment A - email thread between MISO Small and NoCapX/Prehn Overland

Attachment B - FERC Order_ER25-612-000 April 17, 2025, Chair Christie Concurrence

Attachment C - VA Docket PUE-209-00043 PATH Testimony of George C. Loehr

Attachment D - Loehr Testimony, U.S. Senate Energy and Natural Resources Committee from July 31, 2008 - Online at http://www.northbyram.org/routeb/pdf/loehr_testimony.pdf

Attachment E - Xcel Responses to NoCapX/Prehn IR 3 and 2

Subject: RE: [EXT]Re: Filing of Attachment A to Comments Filed on March 28, 2025 in PUC Docket CN-22-532
From: Jeffrey Small <jsmall@misoenergy.org>
Date: 4/1/2025, 10:25 AM
To: "Carol A. Overland" <overland@legalectric.org>

Ms. Overland

Despite you expression of exasperation, you have not identified the jurisdiction and docket number for the Loehr testimony as it was originally presented.

I spoke with Mr. Loehr on Monday. The testimony was filed more than 10 years ago, and he believes it was in Maryland (although he is not certain, the “PATH” project covered multiple states). I expect filings by attorneys to contain citations adequate to locate the source material. You have not provided the jurisdiction or the docket number for the Loehr testimony.

Jeff Small
MISO Legal

From: Carol A. Overland <overland@legalectric.org>
Sent: Tuesday, April 1, 2025 10:47 AM
To: Jeffrey Small <jsmall@misoenergy.org>
Subject: Re: [EXT]Re: Filing of Attachment A to Comments Filed on March 28, 2025 in PUC Docket CN-22-532

Warning! This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the ‘Phish Alert’ button.

Mr. Small

You are confused or missing the identifying information. It's there for the world to see.

Clearly identified:

RE: “NEED” Initial Comment
The Prehn Family & NoCapX 2020
Mankato-Mississippi Transmission Line f/k/a Wilmarth-N Rochester-Tremval
PUC Certificate of Need Docket CN-22-532

The header on the Attachment itself clearly identifies it as PATH Testimony, no claim that it's Testimony for a this docket.

Attachment A - PATH Testimony of George C. Loehr

In the Comment, clearly identifies:

---

[2] PUC Docket CN-06-1115.
[3] See e.g., Attachment A, Testimony of George C. Loehr in the PATH docket, addressing the issues present in this and all other utilities’ MISO Tranche 1 and 2 transmission applications.

Good grief...

Carol

On 4/1/2025 9:15 AM, Jeffrey Small wrote:

Ms. Overland

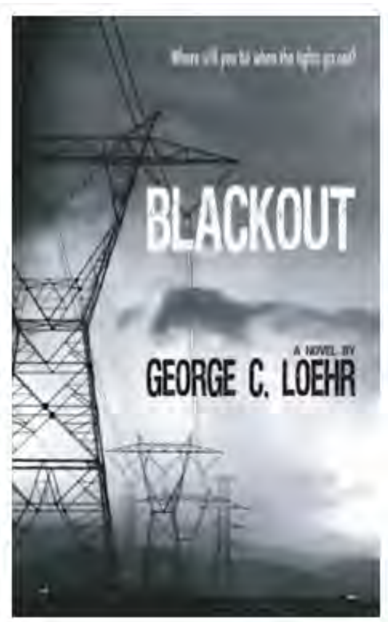
You have yet to identify, with jurisdiction and docket number, the testimony that you attached to your comments in Minnesota. It is deceptive to remove the identifying information on the testimony.

Jeff Small
MISO Legal

From: Carol A. Overland <overland@legalectric.org>
Sent: Monday, March 31, 2025 4:57 PM
To: Jeffrey Small <jsmall@misoenergy.org>
Subject: [EXT]Re: Filing of Attachment A to Comments Filed on March 28, 2025 in PUC Docket CN-22-532

Warning! This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

btw, since you're interested in Loehr's PATH testimony, you may want to check out his novel "Blackout" from 2007. And his attached testimony, article, and saving the best 'til last, his "Dr. Megavar."



On 3/31/2025 3:15 PM, Jeffrey Small wrote:

> Ms. Overland
>
> On March 28, 2025, in Minnesota PUC Docket CN-22-532 you filed as Attachment A the testimony of George C. Loehr. That testimony relates to the Potomac-Appalachian Transmission Highline 765 kV project in the PJM footprint (state of filing and docket not identified). I intend to contact Mr. Loehr regarding that testimony since he does not seem to be engaged by your client for purposes of the Minnesota proceeding (the testimony reflects his engagement by the Sierra Club).
>
> Please let me know whether I am mistaken and that your client has engaged Mr. Loehr for purposes of the Minnesota proceeding.
>
> Jeffrey L. Small
> MISO Legal Department

Attachment A_email thread between MISO Small and NoCapX/Prehn Overland

Subject: Re: Filing of Attachment A to Comments Filed on March 28, 2025 in PUC Docket CN-22-532
From: "Carol A. Overland" <overland@legalectric.org>
Date: 3/31/2025, 3:26 PM
To: Jeffrey Small <jsmall@misoenergy.org>

No, we have not retained Mr. Loehr. **It's an attachment to the Comment, NOT submitted as testimony.** It's an example for people to know about, a matter of public record, clearly identified as testimony from the PATH project. Nowhere did I claim that he was working with us.

On 3/31/2025 3:15 PM, Jeffrey Small wrote:

> Ms. Overland
>
> On March 28, 2025, in Minnesota PUC Docket CN-22-532 you filed as Attachment A the testimony of George C. Loehr. That testimony relates to the Potomac-Appalachian Transmission Highline 765 kV project in the PJM footprint (state of filing and docket not identified). I intend to contact Mr. Loehr regarding that testimony since he does not seem to be engaged by your client for purposes of the Minnesota proceeding (the testimony reflects his engagement by the Sierra Club).
>
> Please let me know whether I am mistaken and that your client has engaged Mr. Loehr for purposes of the Minnesota proceeding.
>
> Jeffrey L. Small
> MISO Legal Department

--

"Our lives begin to end the day we become silent
about the things that matter." Dr. Martin Luther King, Jr.

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191 FERC ¶ 61,056
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Mark C. Christie, Chairman;
Willie L. Phillips, David Rosner
and Lindsay S. See.

PJM Interconnection, L.L.C. | Docket No. ER25-612-000

ORDER DISMISSING WAIVER REQUEST

(Issued April 17, 2025)

1. On November 26, 2024, pursuant to Rules 207 and 212 of the Commission's Rules of Practice and Procedure,[1] PJM Interconnection, L.L.C. (PJM) filed a request for waiver of the requirements of Schedule 6, section 1.5.7(f) of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (Operating Agreement),[2] to allow PJM to extend the deadline for completing its annual market efficiency reevaluation for the Transource Independence Energy Connection Project (Transource IEC Project) until the end of the third quarter of 2025. As discussed below, we dismiss as moot PJM's waiver request.

I. Background

2. Schedule 6 of the Operating Agreement sets forth PJM's Regional Transmission Expansion Planning protocols. As part of the process for developing the Regional Transmission Expansion Plan (RTEP), PJM's Office of the Interconnection will evaluate whether Economic-based Enhancements or Expansions could relieve transmission constraints that have an economic impact.[3] Following PJM Board consideration of the assumptions to identify enhancements or expansions, PJM's Office of the Interconnection will perform a market efficiency analysis to compare the costs and benefits of, in relevant part, adding new enhancements or expansions that could relieve one or more economic

[1] 18 C.F.R. §§ 385.207, 385.212 (2024).

[2] PJM, Intra-PJM Tariffs, Operating Agreement, Schedule 6, § 1.5 (Procedure for Development of the Regional Transmission Expansion Plan) (29.1.0), § 1.5.7(f) (Development of Economic-based Enhancements or Expansions).

[3] *Id.*

constraints.[4] Schedule 6 requires that the relative benefits and costs of an Economic-based Enhancement or Expansion must meet a benefit-to-cost ratio threshold of at least 1.25:1 to be included in the RTEP recommended to the PJM Board.[5]

3. Operating Agreement, Schedule 6, section 1.5.7(f) provides that PJM annually shall review the costs and benefits of constructing such enhancements and expansions and recommend to the PJM Board whether the new Economic-based Enhancements or Expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan.[6]

II. <u>Waiver Request</u>

4. PJM requests waiver of the requirements of Operating Agreement, Schedule 6, section 1.5.7(f) to extend the time for PJM to complete its annual review of the costs and benefits for the Transource IEC Project,[7] an economic project approved by the PJM Board in August 2016 to establish two new 230 kV transmission lines across the Pennsylvania-Maryland border.[8] On September 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the Transource IEC Project, to keep it in the RTEP but remove it from the models PJM uses to perform the annual planning analysis,

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[4] *Id.* § 1.5.7(b).

[5] *Id.* § 1.5.7(d).

[6] *Id.* § 1.5.7(f).

[7] Waiver Request at 3.

[8] *Id.* at 4.

pending any future developments in the regulatory process.[9] The Transource IEC Project remains in suspension.[10]

5. PJM states that it has completed a market efficiency reevaluation of the Transource IEC Project annually since 2017, and in order to perform the 2024 annual market efficiency reevaluation analysis in a way that produces meaningful results, PJM requires a market efficiency model that resolves the reliability violations posted in the 2024 RTEP Window #1.[11] PJM states that it will need to prepare the updated model, but such model will not be completed until at least the second quarter of 2025.[12] PJM requests that its requested waiver remain in effect until the end of the third quarter of 2025 to allow PJM time to complete the 2024 annual market efficiency reevaluation analysis. PJM contends that the waiver request satisfies the Commission's criteria for granting waiver.[13]

III. <u>Notice of Filing and Responsive Pleadings</u>

6. Notice of PJM's filing was published in the *Federal Register*, 89 Fed. Reg. 97604 (Dec. 9, 2024), with interventions and protests due on or before December 10, 2024. Timely motions to intervene were filed by: the Pennsylvania Commission, American Electric Power Service Corporation (AEP),[14] and Monitoring Analytics, LLC, acting in

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[9] *Id.* at 4-5. PJM states that, on May 24, 2021, the Pennsylvania Public Utility Commission (Pennsylvania Commission) denied the Transource IEC Project's Certificate of Public Convenience and Necessity (CPCN) applications. *Id.* n.12. PJM notes that, on June 22, 2021, Transource filed a complaint with the U.S. District Court for the Middle District of Pennsylvania, seeking declaratory and injunctive relief, which the court granted on December 6, 2023. *Id.* PJM states that the matter is now pending at the U.S. Court of Appeals for the Third Circuit. *Id.* (citing *Transource Pa., LLC v. DeFrank*, 705 F. Supp. 3d 266 (M.D. Pa. 2023); *Transource Pa., LLC v. DeFrank*, Case No. 24-1045 (3d Cir. Jan. 09, 2024)).

[10] *Id.* at 5.

[11] *Id.* at 1-2, 4.

[12] *Id.* at 5.

[13] *Id.* at 6.

[14] AEP moves to intervene on behalf of its affiliates, which include: Appalachian Power Company; Indiana Michigan Power Company; Kentucky Power Company; Kingsport Power Company; Ohio Power Company; Wheeling Power Company; AEP Appalachian Transmission Company, Inc.; AEP Indiana Michigan Transmission Company, Inc.; AEP Kentucky Transmission Company, Inc.; AEP Ohio Transmission Company, Inc.; AEP West

its capacity as the Independent Market Monitor for PJM (IMM). The Maryland Public Service Commission (Maryland Commission) filed a motion to intervene out of time.

7. Protests were filed by the Pennsylvania Commission, the IMM, Keryn Newman, Renée Hamidi, STOP MPRP, Inc, Coalition To Protect Franklin County (CTPFC), Lantz W. Sourbier, State Representative Rob Kauffman, Karen I. Benedict, and Franklin Country Visitors Bureau. Comments supporting the waiver request were filed by Transource Pennsylvania, LLC (Transource). On December 17, 2024, PJM filed a motion for leave to answer and answer to the protests. On January 2, 2025, PJM filed a motion for leave to answer and answer to update the status of the waiver request. On April 14, 2025, PJM filed a motion for leave to answer and answer to provide a further update.

A. Protests and Comments

8. Protesters challenge the measurable benefits of the Transource IEC Project[15] and question PJM's adherence to tariff requirements.[16] Protesters contend that PJM should have made a recommendation to the PJM Board in June 2024 to abandon the Transource IEC Project,[17] or that the Pennsylvania Commission's denial of the CPCN for Transource IEC Project should have ended the project.[18] Protesters also assert that PJM's waiver request is a delaying tactic to prevent the cancellation of the Transource IEC Project while the federal court proceedings over the Pennsylvania Commission's decisions rejecting the CPCN applications continue[19] and that it will harm ratepayers.[20]

Virginia Transmission Company, Inc.; and AEP Energy Partners, Inc.

[15] Keryn Newman Protest at 2; Renée Hamidi Protest at 1; STOP MPRP Protest at 2; CTPFC Protest at 3.

[16] Keryn Newman Protest at 2; Renée Hamidi Protest at 1; STOP MPRP Protest at 1-2; CTPFC Protest at 3; State Representative Rob Kauffman Protest at 1.

[17] Newman Protest at 2; Renée Hamidi Protest at 1.

[18] State Representative Rob Kauffman Protest at 1.

[19] Keryn Newman Protest at 3-4; Renée Hamidi Protest at 2; CTPFC Protest at 3; Lantz W. Sourbier Protest at 1; State Representative Rob Kauffman Protest at 1; Karen I. Benedict Protest at 1-2.

[20] Keryn Newman Protest at 3; Renée Hamidi Protest at 2; STOP MPRP Protest at 2; CTPFC Protest at 3; Lantz W. Sourbier Protest at 1-3; State Representative Rob Kauffman Protest at 1-2; Karen I. Benedict Protest at 1-2; Franklin County Visitors

9. Transource supports PJM's waiver request.[21]

B. PJM's December 17, 2024 Answer

10. PJM contends that protesters do not accurately state the scope of the annual review analysis, and that reevaluation is not limited to a benefit-to-cost analysis. PJM contends that the evaluation is a more holistic analysis that includes consideration of multiple factors, including changing system conditions.[22] PJM states that arguments that ratepayers are harmed while the Transource IEC Project remains in the RTEP are speculative and misplaced and that PJM has informed project developers that since the Transource IEC Project was suspended in 2021, only expenditures and obligations that are "reasonably necessary" should be incurred. PJM states that it has no information to suggest that the developers have incurred significant additional construction or equipment costs. Finally, PJM argues that whether to remove the Transource IEC Project, or any other project, from the RTEP is beyond the scope of this narrow proceeding.[23]

C. PJM's January 2, 2025 Answer

11. PJM states that the Transource IEC Project reevaluation was completed using the presently available planning model and the results were posted on the Transmission Expansion Advisory Committee's webpage on December 31, 2024 and that the waiver request is now moot.[24]

D. PJM's April 14, 2025 Answer

12. PJM states that it has developed the 2025 market efficiency planning model and presented it to PJM stakeholders at the March 2025 Transmission Expansion Advisory Committee meeting.[25] PJM further states that it is in the process of performing the 2025

Bureau Protest at 1; Pennsylvania Commission Protest at 4.

[21] Transource Comments at 3.

[22] PJM Dec. 17, 2024 Answer at 3-4, 6 & n.10. PJM cites changes in load forecasts, and anticipated merchant transmission facilities, generation, and demand response, as part of the more holistic analysis required by Schedule 6, section 1.5.7(f) of the Operating Agreement.

[23] *Id.* at 3-4.

[24] PJM Jan. 2, 2025 Answer at 1-2.

[25] PJM Apr. 14, 2025 Answer at 1-2.

annual re-evaluation of the Transource IEC Project using the updated model, and anticipates having the results of the re-evaluation finalized by May 1, 2025.[26]

IV. Discussion

A. Procedural Matters

13. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2024), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

14. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d), we grant the Maryland Commission's late-filed motion to intervene given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

15. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2024), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We accept PJM's answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

16. We dismiss as moot PJM's request for waiver of the requirements of Schedule 6, section 1.5.7(f) of the Operating Agreement to allow PJM to extend the deadline for completing its annual market efficiency reevaluation for the Transource IEC Project. In its January 2, 2025 answer, PJM states that it completed the Transource IEC Project reevaluation using the presently available planning model and posted the results on the Transmission Expansion Advisory Committee's webpage on December 31, 2024. We find that these circumstances render PJM's waiver request moot, and therefore we dismiss the request. Because we are dismissing PJM's waiver request, we do not address the protests or comments to PJM's filing.

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[26] *Id.* at 2.

The Commission orders:

PJM's waiver request is hereby dismissed as moot, as discussed in the body of this order.

By the Commission. Chairman Christie is concurring with a separate statement attached.
Commissioner Chang is not participating.

(S E A L)

Carlos D. Clay,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. ER25-612-000

(Issued April 17, 2025)

CHRISTIE, Chairman, *concurring*:

1. In December 2023, I wrote a concurrence to a seemingly routine letter order closing the long running PATH transmission project.[1] That was the transmission project for which consumers in PJM paid approximately a quarter billion dollars without a single state ever approving a certificate of public convenience and necessity (CPCN), nor a single ounce of steel ever going into the ground. I said in that concurrence that the letter order may not seem noteworthy, but ". . . as Willy Loman's wife said in *Death of a Salesman,* 'attention *must be paid*.'"[2] As the debate continues over whether to grant to transmission owners who joined PJM or other RTOs/ISOs a *perpetual* adder of 50 or more basis points to their return on equity (profit) – which flows right into hard-pressed consumers' power bills – attention must be paid to this seemingly routine order as well.

2. While I agree that PJM's waiver request in this matter is moot, what is remarkable is that this matter is even before us. This specific transmission project, being developed by Transource, was denied a certificate of public convenience and necessity (CPCN) by the Pennsylvania Public Utility Commission (PA PUC) *nearly four years ago*. After conducting its own proceeding under its state laws and considering the evidence, the PA PUC found the project was not needed to serve consumers in Pennsylvania.[3] Not willing to accept the considered decision of the state utility commission of Pennsylvania, PJM and Transource then appealed the decision of the PA PUC to federal court.

3. In their federal court filings, PJM and Transource argue that the mere fact that PJM planned a project that was put into the PJM regional transmission plan (RTEP) was an act sufficient to pre-empt a state's sovereign police power authority to conduct a

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[1] *See Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (2023) (Christie, Comm'r, concurring), https://cms.ferc.gov/news-events/news/e-4-commissioner-christies-concurrence-letter-order-approving-path-settlement-er12.

[2] *Id.* P 1 (emphasis in original).

[3] *See, e.g.*, https://www.puc.pa.gov/press-release/2021/puc-denies-transource-applications-for-high-voltage-transmission-line-projects-in-franklin-and-york-counties.

CPCN proceeding and to determine whether the project was needed to serve its own consumers.[4] After all, *Pennsylvania consumers will pay* for the project under PJM's cost allocation formula.

4. The claim that, because PJM and other RTOs are federally regulated, the inclusion of a PJM-planned transmission project in PJM's RTEP effectively pre-empts a state's inherent police power authority to approve that and other utility projects within its borders is, frankly, outrageous. FERC Order No. 1000, which set up the entire regional planning regime under which PJM and other RTOs now operate, said the opposite.[5]

5. Some history is quite relevant here:

6. In 2004, Virginia's largest utility, Dominion Virginia Power, received the approval it sought from the Virginia State Corporation Commission (Virginia Commission or SCC) to join PJM.[6] In the SCC order approving that application to join PJM, there was incorporated a Partial Stipulation agreed to by, among other parties, *PJM itself*. That Partial Stipulation included the following provision:

> *Nothing in this Partial Stipulation or the SCC's approval thereof shall be deemed to alter in any way* the existing obligation of Dominion Virginia Power under the laws of the Commonwealth of Virginia *to seek a certificate of public convenience and necessity prior to commencing to construct* an electric generation facility or *transmission facility*.[7]

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[4] *See, e.g.*, Brief of Appellee Transource Pennsylvania, LLC. (Transource Third Circuit Brief) at 3-7 and *passim*, Steven DeFrank, et al., v. Transource Pennsylvania, LLC., No. 24-1045 (3d Cir. July 10, 2024); Brief for Amicus Curiae PJM Interconnection, L.L.C. Supporting Appellee [Transource] and Supporting Affirmance at 2-3 and *passim*, Steven DeFrank, et al., v. Transource Pennsylvania, LLC., No. 24-1045 (3d Cir. July 17, 2024).

[5] *See, e.g.*, *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at PP 227, 253 n.231, 287 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 342, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[6] *Commonwealth of Va. ex rel. State Corp. Comm'n*, Case No. PUE-2000-00551 (Nov. 10, 2004). I participated in the proceeding as a member of the Virginia Commission.

[7] *Id.* at Partial Stipulation No. 6 (emphases added).

7. But there's more history, much more:

8. Earlier that same year, Appalachian Power Company doing business as American Electric Power – Virginia (AEP-VA) also sought and received approval from the Virginia Commission to join PJM.[8] As with Dominion's order of approval, AEP's approval order incorporated a Stipulation that included the following provision:

> Nothing in this Stipulation or the SCC's approval thereof shall be deemed *to alter in any way* the existing obligation of Appalachian [*AEP-VA*] under the laws of the Commonwealth of Virginia *to seek a certificate of public convenience and necessity* prior to commencing to construct an electric generation facility or *transmission facilities*.[9]

9. AEP is one of the owners of Transource.[10]

10. Today both Transource Pennsylvania, majority owned by AEP, and PJM, are arguing in federal court that the Commonwealth of Pennsylvania – and by logical extension *all states including the Commonwealth of Virginia* – are *pre-empted* from exercising their CPCN laws to approve – or reject – a project once that project has been planned by PJM for its regional plan. Should AEP and PJM succeed in persuading a federal court that the mere selection of a transmission project planned by PJM acts to pre-empt the states' CPCN laws – a position vigorously opposed by all the states as expressed by the National Association of Regulatory State Commissioners (NARUC)[11] – such a ruling will likely be a Pyrrhic victory of monumental proportions. Such an

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[8] *Commonwealth of Va. ex rel. State Corp. Comm'n*, Case No. PUE-2000-00550 (Aug. 30, 2004). I also participated in this proceeding as a member of the Virginia Commission.

[9] *Id.* at Stipulation No. 7 (emphasis added). AEP's explicit agreement to this Stipulation was signed by its counsel in the case. PJM also signed and explicitly agreed to this Stipulation. *See* signature sheets attached to Stipulation.

[10] *See, e.g.*, Transource Third Circuit Brief at i ("Transource Pennsylvania, LLC is owned 100% by Transource Energy, LLC. Transource Energy, LLC is owned 86.5% by AEP Transmission Holding Company, LLC . . . . AEP Transmission Holding Company, LLC is a wholly owned subsidiary of American Electric Power Company, Inc., which is a publicly traded company."); *see RPC Power, LLC*, 188 FERC ¶ 61,123, at P 17 n.19 (2024); *Transource Pa., LLC*, 184 FERC ¶ 61,091, at P 9 (2023).

[11] *See, e.g.*, Brief of Amicus Curiae the National Association of Regulatory Utility Commissioners Supporting Defendants-Appellants Petition Seeking Reversal, Steven DeFrank, et al., v. Transource Pennsylvania, LLC., No. 24-1045 (3d Cir. May 17, 2024).

outcome will tell the states, which retain the authority under their inherent police powers to decide whether to allow their utilities to join, not join, or leave RTOs, that the rules of the game have been changed radically after the fact – without the states' agreement and, as the history recounted herein shows, *contrary to earlier pledges to respect state laws.* So perhaps state perspectives on RTO membership for their utilities should be reconsidered.

11. Further, under this Commission's formula rate structure, Transource, like any other transmission developer that has been awarded the Construction Work In Progress (CWIP) incentive, can collect costs from consumers just as soon as the project goes into the RTEP, without regard to whether a state commission has approved the project or, in this case, even if a state commission has actually considered and *rejected* the CPCN.[12]

12. So this case is redolent of the infamous PATH case referenced in paragraph 1 above. As I wrote in my concurrence to the December 2023 letter order, in that case the developers collected roughly a *quarter billion dollars* from consumers through FERC's formula rates – rates that under FERC policy come with a presumption of prudence – and which were inflated by the many incentives (*i.e.*, "FERC candy") that FERC showered on the developers of PATH.[13]

13. More history: AEP was one of the developers of PATH.[14]

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[12] I note that Transource Pennsylvania, the specific portion of the Transource project that was rejected by the PA PUC, includes CWIP in recoverable rate base. As PJM notes in this docket, on September 22, 2021, the PJM Board endorsed the recommendation of PJM to suspend the project and that PJM reminded the developers that expenditures and obligations related to the project '"should only be incurred as they are reasonably necessary. . . .'" Waiver Request at 4-5; PJM December 17, 2024 Answer at 6 (citation omitted). At the end of 2021, Transource Pennsylvania's April 14, 2022 FERC Form 1 showed $77.9 million in CWIP (Account 107) for this project. April 14, 2022 Transource Pennsylvania FERC Form 1 Year End 2021/Q4 at 110-111, 216. In its April 8, 2025 FERC Form 1 filing made just 9 days ago, that figure as of the end of 2024 had risen to $93.3 million (Account 107). April 8, 2025 Transource Pennsylvania FERC Form 1 Year End 2024/Q4 at 108-109, 216.

[13] *See Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (2023) (Christie, Comm'r, concurring at PP 2-3), https://cms.ferc.gov/news-events/news/e-4-commissioner-christies-concurrence-letter-order-approving-path-settlement-er12.

[14] *E.g.*, *id.* P 2 n.2.

14. As transmission costs rise rapidly in PJM, as well as in all other RTOs, it is past time for this Commission to fulfill its duty to ensure "just and reasonable rates" under the Federal Power Act by protecting consumers from the costs of FERC's own policies that are inflating those rapidly rising transmission costs. And to be more specific, as the debate continues over whether to give transmission developers/owners a perpetual ROE adder for joining an RTO, the history recited herein is extremely relevant. History matters.

For these reasons, I respectfully concur.

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Mark C. Christie
Chairman

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TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George C. Loehr, and my business address is 4101 Killington Rd. NW, Albuquerque, NM 87114.

Q. BY WHOM ARE YOU EMPLOYED?

A. At present, I am self-employed.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Electrical Engineering degree from Manhattan College in 1962, and immediately began my engineering career with the Consolidated Edison Company of New York, working in bulk power transmission planning. I also pursued graduate studies at New York University, from which I received a Master of Arts in English Literature in 1964. Also in 1964, Con Edison enrolled me in the General Electric

Power Systems Engineering Course (PSEC) in Schenectady, NY, which I completed in 1965. Following the 1965 Northeast Blackout, I was actively involved in a wide range of follow-up activities. For example, I was Chairman of the Computer Committee, Federal Power Commission System Studies Group, Interconnected System. My committee completed an accurate computer simulation of the event – the first such successful simulation of a widespread power failure in North America. I was later named Division Engineer of Con Edison's Transmission Planning Division.

I joined the New York Power Authority (NYPA) as Chief Planning Engineer in 1969. Up until that time, all of NYPA's system planning had been by consultants, and my first assignment was to recruit and train a planning staff. I was responsible for management of the planning staff and the conduct of all NYPA bulk power system generation and transmission planning activities, which included load flow, transient stability, and loss of load expectation studies. I also served on many New York Power Pool and Northeast Power Coordinating Council committees and task forces.

I was hired by the Northeast Power Coordinating Council (NPCC) in 1972. Again, my first assignment was to recruit and train a technical staff. My major responsibilities were to manage the NPCC staff, which worked in support of the eight NPCC expert task forces, and to advise NPCC's Joint Coordinating Committees and Executive Committee. I became very active in regional, national and North American Electric Reliability Council (NERC) activities, and served on numerous committees, subcommittees and task forces. I also served on a Federal Power Commission advisory committee following the

1977 New York City Blackout. I was named Executive Director of NPCC in 1989, and remained in that position until my (early) retirement in 1997.

Since retiring from the NPCC, I have done management consulting, appeared as an expert witness, and taught a variety of courses on power systems – especially courses and workshops for non-technical professionals. My clients have included organizations throughout the U.S., Canada, and China.

At present, I am an Unaffiliated Member of the Executive Committee of the New York State Reliability Council (NYSRC), and currently serve as its Chair; I formerly chaired the NYSRC's Reliability Compliance Monitoring Subcommittee. In addition, I serve as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC), and as a member of its Audit Committee. I have served as Vice President and a member of the Board of Directors of the American Education Institute (AEI), and I was a charter member of Power Engineers Supporting Truth (PEST). I have given expert testimony in the states of Maine, Pennsylvania, New York, Vermont, Kentucky, New Mexico, Mississippi, and in Washington, DC. I have done TV interviews with BBC, CNN, WPIX and CBC, and have been a lecturer, keynote speaker, and/or chair at professional conferences in the U.S. and Canada. In addition, I've made audio tape lectures for various organizations, including the Institute of Electrical and Electronics Engineers (IEEE), Professional Development Options, Red Vector, and AEI. My articles have appeared widely in the trade press, including *Public Utilities Fortnightly, Electrical World, The Electricity Journal, Electricity Daily, Transmission &*

Distribution World, Energy Perspective, Restructuring Today, Energy Pulse, Natural Gas & Electricity, EnergyBiz, and the Belgian magazine, *Revue E tijdschrift*. I have been quoted in a number of U.S. newspapers, and interviewed on Michigan public radio. *The New York Times* published an op-ed piece of mine in 2006. I am co-editor of and a contributor to the IEEE book, *The Evolution of Electric Power Transmission Under Deregulation*.

In addition to my engineering career, I am a published author, have exhibited my art photographs at galleries in the New York metropolitan area, and have done stock photography for The Image Bank, a world-wide photo agency. My photos have appeared in numerous magazines, advertisements, business brochures, in several "coffee table" books, and as a book cover of a best seller. I recently published my own first novel, *Blackout*.

Q. PLEASE EXPLAIN THE MISSION OF THE NEW YORK STATE RELIABILITY COUNCIL (NYSRC).

A. The mission of the New York State Reliability Council is to promote and preserve the reliability of the New York State Power System in the New York Control Area. This mission includes developing, maintaining, and from time-to-time, updating the Reliability Rules which must be complied with by the New York Independent System Operator and all Market Participants. In fulfilling its mission, it works in close conjunction with the New York Independent System Operator. It carries out its mission in accordance with the New York State Reliability Council Agreement and the New York Independent System Operator/New York State Reliability Council Agreement.

Q. PLEASE EXPLAIN THE MISSION OF THE NORTHEAST POWER COORDINATING COUNCIL (NPCC).

A. The Northeast Power Coordinating Council (NPCC) was the first of the Regional Reliability Councils formed after the Northeast Blackout in 1965. Its role was (and is) to ensure the reliability of electric power systems in the northeastern United States and central and eastern Canada by developing, maintaining, and monitoring conformance with reliability criteria for planning and operations. It also provides a forum for the coordination of planning and operating procedures. NPCC's current membership encompasses New York State, the six New England states, and the Canadian provinces of Ontario, Quebec, New Brunswick, Nova Scotia, and Prince Edward Island. I might add that the main reason I left the New York Power Authority and joined NPCC was my keen interest in reliability and reliability criteria, and my wish to contribute toward making the bulk power system more reliable.

Q. PLEASE EXPLAIN THE ORGANIZATION KNOWN AS POWER ENGINEERS SUPPORTING TRUTH (PEST).

A. Following the August 14, 2003 blackout, several associates and myself, each with 40 years or more experience in electric power system planning and reliability, decided to form a group to bring out the truth about electric power system reliability. To this end, we established a not-for-profit organization, which we called Power Engineers Supporting Truth (PEST). As we stated in our *Principles*, which were issued in September 2003, our intent was "to identify the best ways to make the bulk power systems in the United States both more reliable and economic." We published several reports over the next few years, and made our reviews and recommendations available to the general public, as well as to interested industry groups, government officials, and the media.

Q. HAS THERE BEEN A COMMON THREAD TO YOUR TESTIMONY IN STATES SUCH AS MAINE, PENNSYLVANIA, NEW YORK, VERMONT, KENTUCKY, NEW MEXICO, AND MISSISSIPPI?

A. Yes. My expert testimony in the various states has focused on bulk power system reliability. So have my TV and radio interviews, my articles in the trade press, and my conversations with reporters and journalists.

Q. WHAT IS THE SUBJECT OF THE COURSES AND WORKSHOPS YOU NOW TEACH?

A. Virtually all of my courses and workshops, my speeches and lectures, and my audio tapes primarily address two subjects: how the interconnected bulk power system (or "grid") works, and the importance of keeping it reliable.

Q. HAS MOST OF YOUR CAREER FOCUSED ON ENSURING THE RELIABILITY OF BULK POWER SYSTEMS?

A. I would say that "bulk power system reliability" is the one concept that best characterizes my 47 year career. It is even the main subject of my recently published novel, *Blackout*.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY HERE?

A. I was asked by the Sierra Club to complete an independent evaluation of the PATH application and determine if the applicants had proven a reliability need for the line. I reviewed the PATH application, the testimony and exhibits submitted with the application, and numerous discovery responses and documents from the various parties.

Q. COULD YOU SUMMARIZE YOUR VIEWS?

A. A reliability need for the proposed 765kV line has not been clearly demonstrated. My major reservation is with the assumptions that underlie the contingency studies – especially the conditions assumed for the base case load flows upon which the contingency studies were run. More specifically:

- The applicants and PJM do not have *carte blanche* from NERC. While PJM has been designated by NERC as a Planning Authority (a.k.a. Planning

Coordinator since 2007) and Transmission Planner, it is not authorized to make whatever assumptions it wants when conducting planning studies. In my opinion, the assumptions and base conditions of the applicant's and PJM's studies are not credible and reasonable. Therefore, neither are the conclusions.

- PATH would not improve reliability. Rather, by making eastern load centers all the way from northern New Jersey to northern Virginia more dependent on remote generation and transmission lines hundreds of miles in length, PATH would *exacerbate* reliability.

- PATH would effectively provide a subsidy to existing and future western generators – access to the lucrative eastern load centers without cost to themselves. Conversely, the western subsidies would place eastern generators at a significant disadvantage. This is a clear violation of FERC's "fair and non-discriminatory" principle.

- PATH would encourage remote rather than local generation by providing western generators with free transmission access to eastern load centers. Existing coal-fired generators would be ramped up, and new coal-fired generators would be encouraged to site in the west.

- PATH's approval now, before commitments need to be made for generators and other resources, would be a strong incentive to increase the output of existing coal-fired plants, and for developers to build western generation. It would be a disincentive for developers to site future generation and other resources in the East, where they're most needed.

• PJM planning studies represent future generators which have executed only a Facilities Study Agreement (FSA) if they add to a reliability problem, but require the next step, an Interconnection Services Agreement (ISA), if they contribute to a solution. This is a clear case of bias, and violates FERC's "fair and non-discriminatory" principle. More important, it does not make engineering sense.

• The applicants seem focused almost exclusively on AC EHV transmission. Non-transmission alternatives, and even other transmission alternatives like HVDC, have been ignored.

• PJM's one-at-a-time planning is a piecemeal approach to solving reliability problems. PJM, as the RTO, needs to step up to the plate and start planning its system on a coordinated, integrated basis.

• In my view, the Load Deliverability procedure used by PJM comes up with Capacity Emergency Transfer Objective (CETO) values that are unnecessarily high, and seems out of synch with what the rest of the industry is doing. There are better, more systematic and technically consistent ways to determine the import capabilities required by Load Deliverability Areas (LDAs) to maintain reliability.

• Without PATH, the capability of the Mid-Atlantic LDA to import power would still be in excess of 6,000MW. In other words, with a 6,000MW transfer into the Mid-Atlantic area, there would be no reliability violations. Not one.

• In my opinion, NERC violations have not been established since the base case assumptions are too conservative. So, too, are the CETO/Load Deliverability procedures.

• PJM's procedure for establishing CETO values is far more conservative than other eastern ISO/RTOs. It's ultra-conservative when compared to New York and New England.

• In general, the PJM process for assessing reliability and determining "need" seems to favor extreme solutions – solutions far more massive than necessary. This overkill approach violates an important engineering principle: "Don't use a pile driver to hammer tacks."

• All of PJM's load deliverability testing, which it relied on in determining the need for PATH, was based on a single dispatch. NERC standards call for multiple dispatch scenarios: according to a NERC interpretation of Standards

TPL-002 and -003, “a variety of possible dispatches should be included in planning analyses.”

- While NERC Planning Standards call for the system to be stressed, the interpretation of “stress” must be reasonable. PJM and the applicants take the concept of “stress” to unreasonable extremes.

- PATH isn’t really about reliability – it’s about economics. While western generators would earn greater profits, eastern load centers would become more dependent on long EHV transmission lines; thus major East Coast cities like Philadelphia, Baltimore, Washington and Richmond would become more vulnerable to interruptions and blackouts, either from natural phenomena or from terrorist attacks.

- The alleged “voltage stability” problems have not been proven. We’ve been shown “knee-of-the-curve” results from steady state load flows, but no actual time-domain stability results. The alleged voltage violations are also based on the unnecessarily high CETO values. At more realistic CETOs, there would be no violations.

- Other than construction of the 765kV PATH line, solutions to the alleged steady state voltage violations have not been addressed. Apparently, neither power factor improvements by adding capacitors at the distribution and subtransmission level, nor shunt capacitors at 115/138kV substations, have been considered.

• Despite the fact that the latest “re-tool” analyses show different violations occurring on lower voltage facilities in a time-frame further out in the future, no alternatives to PATH as originally proposed have been examined.

• Conclusions regarding reliability violations beyond the 2014 study year were based on extrapolated results. In my opinion, this is not an acceptable way to assess the reliability of plan the bulk power transmission system.

• The PATH “solution” is not consistent with the alleged need to improve reliability. To improve reliability, PJM needs to promote the location of generation and other resources close to the load centers, rather than build a transmission line which will provide an incentive for the construction of generation, probably coal-fired, hundreds of miles away.

• The *real* reliability problem in PJM is the present high dependence of the eastern load centers on remote generation and multiple EHV transmission lines, each hundreds of miles long. *This* is the problem PJM should be addressing; instead, PJM is pursuing policies which will make the problem worse.

Q. PLEASE EXPLAIN THE HISTORY AND BASIC CONCEPTS INVOLVED IN BULK POWER SYSTEM PLANNING AND RELIABILITY

A. Among the more important considerations when dealing with large power systems are the reliability standards or criteria used for planning and operations. These have been an integral part of the electric power industry since the very first systems were developed in the late 19th Century, but they became increasingly important as power systems expanded and merged to form what we now know as synchronous interconnections, or simply "grids."

Early "central station" systems were relatively simple. A major disturbance or "contingency" could, at worst, shut down electric service in a small area – e.g., one square mile. But the introduction of high voltage alternating current technology permitted the use of long lines at higher voltage. This led to power systems which spanned progressively larger areas. Also, systems found it advantageous to share generating reserves, and minimize reliability risks from transmission problems, by interconnecting with each other.

This process took place through most of the 20th Century until, by the early 1960s, power systems in most of the U.S. and Canada had coalesced into four large synchronous interconnections or "grids." The largest of these, the Eastern Interconnection, stretches from the Canadian Maritimes to Florida, and from the Atlantic Ocean roughly to eastern Montana, Wyoming, Colorado and New Mexico. It encompasses all eastern, central and prairie provinces of Canada except Quebec and Newfoundland. The Western Interconnection runs from the Rockies to the Pacific Coast, and includes the Canadian provinces of Alberta and British Columbia, as well as a small portion of the northern Baja in Mexico. The ERCOT Interconnection comprises approximately 75% of the state of Texas. Finally, the Quebec Interconnection consists of that province in its entirety.

Power system planning begins with today's system – electric system planners do not have the option of throwing away last year's (or last decade's) thinking and starting over from scratch. So the power system as it exists is the starting point. Along with that, planners must begin with today's system demand levels, and predict or "forecast" how customer actions will affect electric demand in the future. In the present "deregulated" or "restructured" electric power industry, the ownership of generating resources in many states is separate from the ownership of the bulk power transmission system. Generation is also competitive – various companies vie with one another in an open market.

There are two aspects to effective reliability: "resource adequacy," having enough generation and other resources to meet the customers' electrical demand; and "transmission reliability," the ability of the transmission system to deliver the power and withstand sudden contingencies without overloads, low voltages, instability, or loss of customer load. To meet these twin goals, power systems must establish certain standards for both planning and operations.

Resource adequacy (generation, DSM, etc.) is determined on a probabilistic basis. In most North America systems, the generally applied standard is "one day in ten years." This means that sufficient resources must be available to serve all firm customer demand on all but one day over a ten year period. Resource adequacy problems, or shortages in generating capacity and other resources, can lead to voltage reductions (or "brownouts"), public appeals, and rotating feeder outages. By their nature, they can usually be anticipated in advance, and actions taken ahead of time.

Transmission reliability is assessed on a deterministic basis. Transmission planning standards or criteria specify a variety of specific disturbances or "contingencies" – the bulk power system must be able to withstand any of these without adverse consequences. Failures of the transmission system can lead to overloads, cascading outages, instability, system separations – and total blackouts over widespread areas. They almost always occur without warning, and can rarely be anticipated; hence, preventive actions, other than scrupulous adherence to standards and criteria, generally are not possible.

Blackouts are usually caused by contingencies more severe than those specified in the applicable standards or criteria, by equipment failures, control system problems, human error, or some combination of these. They involve the break-up of the bulk power transmission system. Blackouts are not caused by shortages of generating capacity.

During the first half of the 20th Century, individual power systems each developed and applied their own planning criteria. By mid-century, however, with the dramatic growth of synchronous interconnections and the increasing use of the system to transmit power over long distances, the limitations of such an approach were becoming obvious. When the Northeast Blackout of 1965 occurred, it was plain to see that a more coordinated approach was necessary.

PJM, which had a much smaller footprint in 1965 than it has today, was already functioning with a uniform set of criteria. The systems involved in the 1965 blackout soon followed suit. Shortly after the blackout, they formed the Northeast Power Coordinating Council (NPCC). Other utilities across North America also formed their own regional reliability councils, which eventually encompassed most of the continent.

Each regional council established its own reliability criteria. Each also developed procedures for assessing conformance. Individual systems and power pools sometimes developed their own more detailed or more stringent criteria, but they were always responsible for adherence to the regional criteria as a minimum.

The regional reliability councils formed the National Electric Reliability Council (NERC) in 1968 to coordinate their activities nationally and develop overall reliability guidelines for their collective systems. NERC has evolved over the years. As additional Canadian systems became members, it became the North American Electric Reliability Council. But the most dramatic changes occurred in the wake of the August 14, 2003 Midwest/Middle Atlantic blackout. The Energy Policy Act of 2005 (EPAct) directed FERC to establish an Electric Reliability Organization (ERO). Its major role would be to develop and enforce mandatory reliability standards for planning and operations. After a period of study, FERC designated NERC as the ERO, and its name was changed to the North American Electric Reliability Council Inc.

Today, NERC develops reliability standards, which must be approved by FERC. The regional reliability councils may have their own criteria, but these must conform to NERC's. As provided by EPAct, compliance with NERC standards is mandatory. ISOs, RTOs and individual utilities, as well as all other market participants like generators and power marketers, are members of the regional reliability councils and must comply with both the regional criteria and NERC standards.

NERC planning standards require both short- and long-term studies. Any violations discovered in the short-term analyses must be addressed with appropriate solutions. On the other hand, the purpose of the long-term studies is to provide some indication of the nature and direction of future reliability problems, and to ensure that any recommended short-term solutions will be consistent with future needs.

Q. HOW ARE STANDARDS AND CRITERIA USED IN TRANSMISSION PLANNING?

A. The first step in evaluating the potential reliability need for new facilities is to investigate the existing transmission system for a chosen future year, with existing and planned generating resources added, along with any transmission additions already scheduled. First, power flow or "base load flow" cases are created, representing base conditions – generally, peak loads under various generation scenarios. Then, new load flow cases are run simulating a wide range of potential disturbances or contingencies. The results of these contingency load flows will indicate where and to what extent the existing system needs reinforcement. At this point, familiarity with the system and engineering judgment will usually suggest potential solutions to the violations, and typically several will be chosen for further scrutiny. The most successful enhancement will be chosen, consistent with a parallel cost-effectiveness analysis. Finally, non-transmission alternatives should also be identified and examined, and compared in terms of cost, reliability, and environmental impact with the preferred transmission solution.

One of the key questions is how severe the contingencies should be. Over the past fifty years, planning engineers have reached a consensus on what is commonly known as "worst single contingency" design – a.k.a. "n-1." This means that the system must be able to survive the worst single event which could happen to the bulk power system. Typically, this is the loss of a large generating unit, or a three-phase fault on a major transmission line or autotransformer. But the devil, as is said, is in the details.

Current NERC standards allow the planning entity a degree of judgment. NERC's TPL-002 and TPL-003, for example, require that the pre-disturbance system be *stressed*; however, the nature of the "stress" is not defined – despite several requests from transmission companies for a more definitive interpretation. It's up to the planning entity to fill in the details.

Specifically, NERC states in its February 8, 2005 interpretation of Standards TPL-002 and -003 that “a variety of possible dispatches should be included in planning analyses.” NERC also specifies that the “selection of ‘critical system conditions’ and its associated generation dispatch falls within the purview of [the Planning Coordinator’s] ‘methodology.’” Finally, NERC directs that “a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.” One of the problems I have with the PJM approach is that only a single dispatch is used for all of the load deliverability analyses relied on in this proceeding.

Base conditions provide another example where the planning entity’s judgment is required. This would include assumptions regarding appropriate load level, the handling of proposed new generation, the potential retirement or older generating units, and the dispatch of the overall system. Dispatch scenarios, which can be viewed as the bridge between “adequacy” (sufficiency of resources) and “operating reliability” (transmission reliability), are of particular interest. Generally, the best approach is to examine several different dispatch scenarios – varying the components and applying the most serious contingencies in each example.

Many planning entities today use a so-called “90/10” load forecast, as opposed to a “50/50” forecast, as one of many ways to satisfy the NERC “critical system conditions” requirement. This means that there is a 10% probability that the actual load will exceed the forecast demand, and a 90% probability that the actual peak demand will be lower.

In conducting planning studies, the critical contingencies as defined by the NERC standards are applied to the modeled system for each chosen scenario. Some of these contingencies will involve the sudden loss of a single element (n-1) – this could be a generating unit, critical transmission line, transformer, or any other power system component. Others contingencies will cause simultaneous loss of two related elements – such as both circuits of a double-circuit transmission line. Since the loss of both elements is caused by a single event, these are also referred to as n-1 contingencies. A few will involve the loss of two unrelated elements (n-1-1), with manual system adjustments between the two contingencies (usually within 10 minutes). Regardless of the contingency applied, the system must suffer no overloads, low voltages, cascading outages, instability, system separation or loss of firm customer load before adjustment.

Q. ARE THE RELIABILITY STANDARDS MANDATED BY NERC?

A. For some time, NERC has developed reliability standards for planning and operations. As a result of the Energy Policy Act of 2005 (EPAct), these are now mandatory under federal law. The NERC planning standards define the contingencies which the power system must be able to survive without significant adverse consequences – overloads, low voltages, instability, system separations, or blackouts. However, the NERC standards do *not* define the configuration of the system to which these contingencies are applied, other than to say that the system must be stressed – assumed base conditions must "cover critical system conditions and study years as deemed appropriate by the responsible entity." [NERC Standards TPL-002-0 and TPL-

003-0.] But the nature of the "critical system conditions" must be credible and reasonable.

NERC has designated various entities, including PJM, as Planning Authorities (Planning Coordinators) and Transmission Planners, as described in the NERC Functional Model. These are responsible for deciding how their systems will be configured – stressed – for application of the NERC contingencies. As NERC has stated, "The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority." [March 13, 2008 NERC Planning Committee interpretation of TPL-002-0 and TPL-003-0.] The language here (e.g. use of the word "credible") clearly indicates that the assumptions must have a basis in reality.

NERC does not scrutinize the manner in which the PJM or any planning entity's system is represented. Neither does FERC. NERC and FERC are not the drivers – the applicants and PJM are the drivers. And they must answer for the base system assumptions they have made.

In my opinion as an expert, the manner in which PJM and the applicants configured the PJM system prior to the application of contingencies went considerably beyond what I consider reasonable. If the base assumptions are not credible, then the contingency analyses based on them are not credible – even though the applied contingencies are those specified in the NERC standards. A house built on sand will not stand. The PATH studies are built on sand; they're based on assumptions, how the PJM system is represented, which are neither credible nor reasonable. Therefore, neither are the conclusions.

Q. BUT NERC HAS DESIGNATED PJM AS A PLANNING AUTHORITY AND TRANSMISSION PLANNER. DOESN'T THAT GIVE PJM AUTHORITY TO MAKE THESE DECISIONS?

A. Not completely – the assumptions must be credible and reasonable. NERC's designation of PJM and other entities as Planning Authorities and Transmission Planners does not give them *carte blanche* to make whatever assumptions they want when conducting reliability assessments and planning studies. NERC neither supports nor condemns PJM's decisions about base conditions – the PJM Load and Generation Deliverability procedure, for example. NERC doesn't endorse *any* planning entity's specific approach. Therefore, the applicants cannot hide behind PJM's designation as a Planning Authority and Transmission Planner to support the need for PATH.

Q. DO YOU BELIEVE THE PATH VIOLATIONS ARE REASONABLE?

A. No. The alleged violations are based on the applicants' initial assumptions, and in my view those are *not* reasonable. Why I believe that the procedures used in the PATH studies are not reasonable is covered in the remainder of my testimony. But the major objection I have is with what I consider an overly conservative process for determining the Capacity Emergency Transfer Objective (CETO), leading to an import target for the

LDA which is unnecessarily high. When the load flows are run to determine if there are any NERC violations, they use this import value; since it's unnecessarily high, finding "violations" is practically guaranteed. With a more reasonable import value, neither thermal nor voltage violations will be found.

Overall, PJM's and applicants' procedures are overly conservative. They pile conservative assumptions on top of conservative assumptions – beyond what, in my opinion, is reasonable. In brief, they push the "conservative" envelope too far.

Q. PLEASE COMMENT ON THE USE OF "CAPACITY EMERGENCY TRANSFER OBJECTIVE" BY PJM AND THE APPLICANTS.

A. For any defined Load Deliverability Area (LDA), PJM does a Loss of Load Expectation (LOLE) study to determine the import capability necessary to maintain a "one day in 25 years" LOLE. This is then called the Capacity Emergency Transfer Objective (CETO) for that LDA. The CETO value is based, among other things, on the load forecast. A mean or median schedule is developed for the LDA, using the same probabilistic statistics as in the LOLE, to accommodate an import equal to the CETO. Next, load flow cases are run at that value, simulating the various requirements of NERC Planning Standards TPL-001, -002, and -003. If the existing transmission system results in "violations" for any of these (A, B, and C), the planners conclude that a transmission reinforcement is required. PJM maintains that they're only permitted to consider transmission reinforcements.

In theory, the Capacity Emergency Transfer Objective (CETO) is the amount of import capability which the LDA geo-electric area would require to allow it to satisfy a chosen loss of load expectation, given its load characteristics and the amount of generation it contains.

Mr. McGlynn discusses the Mid-Atlantic LDA at some length in his testimony. He cites the Mid-Atlantic LDA's CETO used in PJM's April 2009 modeling as 8,190MW [McGlynn, page 28.]. In my opinion, the 8,000MW+ value he comes up with as the CETO is breathtakingly (and unnecessarily) high. That's an awful lot of power to transfer into eastern PJM from the West. It's a very large value to expect to export to *any* single area – something like one MW for every eight MWs of peak load. One has to ask if this is really a reliable way to supply a high percentage of the electric requirements of a metropolitan area that stretches from northern New Jersey to northern Virginia. That entire megalopolis would be subject to interruption by many and diverse causes, natural and human, intentional as well as unintentional. The present import capability of the Mid-Atlantic LDA is in excess of 6,000MW – a pretty high number itself. (Exhibit PFM3 lists the most restrictive contingency at a Mid-Atlantic LDA import of 6,240MW.) In other words, without PATH, it would still be possible to send more than of 6,000MW into eastern PJM. According to the PATH response to SierraVA-IV-61, there is 67,635MW of generating capacity in the Mid-Atlantic LDA as of October 2009 – *right now*. Given this amount of *existing* generating capacity, not even counting whatever additional capacity will be added over the next five years, why isn't a 6,000MW CETO enough? PJM should place greater emphasis on incenting new generation to locate within the Mid-Atlantic LDA, which would provide greater reliability to the eastern load centers.

In responding to the VAStaff-V-5 request for updated data on the Mid-Atlantic LDA, PJM cited a lower peak load forecast for 2014, an 827MW increase in installed capacity, and a lower CETO value – 7,720MW. This CETO reduction of 470MW further reduces any alleged "need" for the PATH line.

PJM's "one day in 25 years" standard – used to come up with the CETO number – is also questionable. This is a conservative assumption, PJM admits – part of the need to "stress" the system. To my knowledge, no other RTO or ISO uses a value this high. Why shouldn't PJM use "one day in 10 years," like everyone else? By comparison, one day in 25 years is a higher standard than that used by either ISO New England or the New York ISO, each of which is only about half the size of the Mid-Atlantic LDA. And this is on top of a 90/10 load representation, which would be expected to occur only once every ten years. PJM seems to pile one conservative assumption on top of another.

In fact, I would question whether a criterion of "one day in 10 years" for all of PJM is itself overly conservative, given the large size of the expanded PJM system. The New England and New York ISOs each use an adequacy criterion of one day in 10 years, yet each is approximately one-fourth the size (in MWs) of the PJM system. Standardized to the PJM peak load, New England and New York at one day in 10 years would be equivalent to *four* days in 10 years. New York and New England include metropolitan areas at least as critical as PJM's; why should PJM use a much more conservative reliability criterion? In my opinion, it would not be unreasonable for PJM to use a less conservative criterion, more in keeping with its peak load relative to other ISO/RTOs like the New York ISO and ISO New England. For example, just by changing from a criterion of one day in 25 years to one day in 10 years for the Mid-Atlantic LDA, and putting it on the same loss of load expectation basis as New York and New England, PJM could lower the CETO for the Mid-Atlantic LDA by approximately 3,000MW.

There are other, and in my opinion better, ways to do this kind of analysis. For example, when it studies the LOLE of the entire PJM system to calculate the required installed reserve margin, PJM uses a multi-area probabilistic program. It does not model separate areas within PJM, however. PJM could use the same program to model all the LDAs along with the existing transmission transfer capabilities between them, and still target an overall LOLE criterion. A need to increase any of the inter-area transfer capabilities would be evident from such an analysis. Thus PJM could unify the process, and also meet the desired objective vis-à-vis the overall PJM system.

In fact, PJM's process for addressing reliability "need" is far more conservative than necessary. In an earlier case (the proposed Prexy facilities in southwestern Pennsylvania), this overly conservative approach led to a recommendation for a major new 500kV transmission line, which was approved by PJM. In my opinion, such a high voltage facility was clearly unnecessary, and I testified to this during the proceedings. After the state hearings were mostly concluded, the PUC ordered a voluntary collaborative effort. This led to a much simpler, less expensive, and less environmentally intrusive solution involving modifications to the local 138kV system and the addition of shunt capacitors.

The proposed Prexy Facilities were to consist of a new 500kV substation in Washington County called "Prexy", a new 500kV transmission line (36 miles long) in Washington and Greene counties, and three new 138kV lines (running 15 miles) to connect the proposed new substation to the existing transmission system. After the collaborative process, the approved fix reinforced the electric grid without any new 500 kV lines, substations, or 138 kV lines. Instead, it involved installing one new monopole on an existing utility right of way (to allow the connection of two existing lines), adding equipment (capacitors) at five existing substations, and replacing the conductors on 2.5 miles of existing 138 kV lines. The estimated cost for the agreed-upon fix is $11.6 million, instead of $213 million for the proposed Prexy Facilities. And the solution solved the same reliability issues that were "driving the need" for the previously proposed "Prexy Facilities."

PJM's approval of the need for Prexy facilities, and PATH in this proceeding, violated an engineering principle which a former professor of mine used to insist on: "Don't use a pile driver to hammer tacks."

Q. WOULDN'T THERE BE VIOLATIONS OF THE MANDATORY NERC STANDARDS IF PATH IS NOT BUILT?

A. Not at all. Whether or not violations will occur ultimately depends on the value selected for the CETO. This applies to voltage as well as line loading violations. There would be *no* violations of NERC Standards if realistic CETO values were used. The only reason that "violations" were identified in PJM's studies is that PJM was trying to cram too much power from outside (essentially western PJM) into the eastern LDAs by using unnecessarily high CETO values. It's sort of like a mouse trying to swallow a lion. For the Mid-Atlantic LDA, without PATH, a 6,000MW CETO would result in zero violations. Zero. And the Mid-Atlantic area would still be capable of importing over 6,000MW.

As I see it, based on my more than 47 years of experience in transmission planning and reliability assessment, eastern PJM is *already* too dependent on western generation – this is the *real* reliability problem, and a major reliability risk.

In my opinion, PJM faces a reliability problem – a *serious* reliability problem – which will worsen if PATH is built. It's the overdependence of the eastern PJM load centers on generating units hundreds of miles to the west. The megalopolis from northern New Jersey to northern Virginia is over-dependent on long transmission lines, any one of which could be taken out of service by natural or human agents. This is a *major* problem that needs to be addressed. And it's a *national security problem* as well. PJM should, in my opinion, develop a program to address this problem as soon as possible – but instead PJM is pursuing policies that will only make the problem worse.

Q. WOULDN'T PATH, IN AND OF ITSELF, INCREASE RELIABILITY ANYWAY?

A. No. Rather than *increase* reliability, PATH would actually make it *worse*. Eastern load centers from Boston to northern Virginia comprise what urban planners sometimes call a linear city or megalopolis. It's essentially one continuous metropolitan area. Within this linear city, the area from northern New Jersey and Philadelphia to Washington and northern Virginia is part of PJM. If PATH is approved, generating companies will be given a powerful incentive to site new generators in the Allegheny coal fields, hundreds of miles to the west, rather than in or close to the eastern load centers. Even existing coal-fired generators will have the opportunity to ramp up their outputs. This will make the eastern megalopolis even more dependent on remote generation resources than it already is. Cities like Newark, Philadelphia, Wilmington, Baltimore, Washington and Richmond will depend for their electric supply on generators hundreds of miles away. I've been in electric power transmission planning and reliability for more than 47 years, but you don't have to be an engineer to understand that this is a less reliable situation than if the resources were located nearby. It's like running an extension cord down the block to plug your toaster into a neighbor's outlet rather than using an outlet in your own kitchen. The long transmission lines are vulnerable to all sorts of interruptions – including terrorist attack – so this is a national security issue as well as a reliability concern.

More transmission does not equal a higher level of reliability. Consider two hypothetical transmission systems: one a system with a lot of transmission lines, but planned and operated to *less* stringent reliability standards; the other a system with very little transmission, but planned and operated to *more* stringent reliability standards. The first system would be less reliable than the second system, because it uses less stringent reliability standards. <u>Reliability is not a function of the amount of wire in the air</u>.

Now consider what happens when transmission is added. The apparent electrical impedance across the grid is reduced, in effect making it electrically tighter. Thus a given contingency could have a more widespread effect. By increasing the amount of west-to-east transmission in PJM, the proposed PATH line would make the Eastern Interconnection subject to larger blackouts.

This can be visualized in a more technical light. The key factor in the stability of a system is the electrical angle between generators. Building transmission lines reduces the equivalent electrical impedance between generators – the units become electrically closer, and the angle is decreased, which tends to make the system more stable. However, stability will be improved *only if no additional power is scheduled across the system*. If the power flow is increased, then the angle is increased, and the units will be electrically further apart, making the system less stable. My own experience after doing this kind of analysis since the early 1960s is that, even if the impedance is decreased and the power flow increased such that the electrical angles are the same, the system will still be more vulnerable to extreme emergency contingencies – those that are more severe than the criteria used in planning and operations, and which are either the major cause or an important contributing cause of nearly all bulk power system blackouts.

When systems build more transmission only to accommodate higher levels of transfer, they push the system harder. The likelihood of instability is increased; the system is more likely to suffer a blackout if an unforeseen contingency occurs, and the blackout is likely to be larger and more damaging. In my opinion, PJM has not proven a reliability problem that requires the construction of PATH, or that PATH will make the overall system more reliable. However, instead of building the PATH line, reliability could be *improved* by promoting additional generating capacity and other resources in the East, close to the load centers. Lower west-to-east transfers across the PJM system would significantly reduce the angle between generators, making the northeast quadrant of the Eastern interconnection less susceptible to instability and blackouts.

Q. DO YOU THINK THAT PJM PLACES TOO MUCH EMPHASIS ON EXTRA HIGH VOLTAGE (EHV) TRANSMISSION LINES?

A. Very definitely. PJM seems to see EHV AC transmission not as the *best* solution to reliability problems, but as the *only* solution. Under the current PJM cost allocation rules, all transmission facilities at 500kV and higher are "socialized" – i.e. their costs are charged to all the Load Serving Entities (LSEs) in PJM essentially in proportion to their electric loads. This means that all customers throughout the PJM area will pay the construction costs for PATH. Because of this "socialization," PATH will provide existing and future western generators, including coal-fired generators, with free access to the eastern load centers. In effect, western generators will be subsidized at the expense of the ratepayers. It's also a case of discrimination against generators and other resource providers in the East.

In other words, western generators will be given market access to eastern load centers without having to pay the cost of providing that access. Customers throughout PJM will bear the full cost of the new transmission. Western generators, both existing and future, will be able to compete with eastern resources without paying for the transmission that makes it possible. This will skew the economics of electric generation supply by subsidizing some generators at the expense of others – and ultimately at the expense of ratepayers. This is not the "fair and non-discriminatory" market that FERC envisaged in promoting "deregulation."

Q. IT HAS BEEN SAID THAT TRANSMISSION PROJECTS MUST BE APPROVED EARLY ON, SINCE THEIR LEAD TIMES ARE NOW LONGER THAN LEAD TIMES FOR GENERATORS.

A. That's true, but early approval of transmission has another, unanticipated consequence. Transmission lead times are now longer than the lead times for generators. That means that transmission projects will generally be approved before generators or other resource providers need to make their commitments. In other words, generating companies can wait until a major transmission line is approved or disapproved before deciding whether to build new generating units in the East or West. If a new line is not planned, or a proposed line isn't approved, developers could site new units in the East, where long EHV lines would not be required to reach load centers. On the other hand, if a line *is* approved, developers are likely to build in the West, where it would be less expensive, since they will be provided transmission access to the eastern load centers at no cost to themselves.

Such transmission approvals would foreclose other options, including generators sited in the East, load management systems, and greater reliance on Reliability Pricing Model (RPM) solutions in general.

In summary, PATH would provide a strong disincentive to anyone considering locating generation or other resources in eastern PJM, and a correspondingly strong incentive to build coal-fired generation in western PJM. The seeming obsession with transmission solutions will not only provide an effective subsidy to existing generators in the West, but it will act as a magnet for siting future generators there, as opposed to locating in the East, where they are really needed.

Q. ARE THERE ANY OTHER EXAMPLES OF DISCRIMINATION IN THE ASSUMPTIONS UNDERLYING THE PATH STUDIES?

A. Yes. To me, an egregious example of PJM's discrimination is how the representation of planned, future generators is handled. In its planning studies, PJM represents only those generators which have executed a Facilities Study Agreement (FSA). To be represented in the studies, generators which would contribute toward the solution of a reliability problem must also have executed an Interconnection Services Agreement (ISA), the next step after the FSA. However, generators which exacerbate a reliability problem are represented even if they have *not* received an ISA. This is patently discriminatory, and in my view is a direct violation of FERC's "fair and non-discriminatory" principle. In defense of this procedure, Mr. McGlynn testifies that more than 75% of all proposed generators eventually drop out, but adds that "5% of requests drop out after an FSA is executed." [McGlynn, page 13, line 2] Mr. McGlynn testifies that only 5% of requests drop out between the execution of an FSA and an ISA. *By McGlynn's own admission*, there's very little difference between the number of generators that complete FSAs and those that complete ISAs – a mere 5%.

In my opinion, no distinction should be made. Any generator which has an executed FSA should be represented, regardless of whether it exacerbates or solves reliability problems. To intentionally discriminate against the very generators which could solve reliability problems is both foolish and potentially costly. It goes against one of the most important principles of FERC and deregulation – that all generators must be treated in a manner that is both fair and non-discriminatory. Finally, again in my opinion, it represents very poor engineering. Good engineering is premised on even-handedness – PJM's biased handling of future generators, based on whether each would contribute to a problem or its solution, tilts the science toward a presumably desired conclusion which might not be proven by a fair and non-discriminatory approach. This constitutes a bias towards transmission and in favor of western coal-fired generators and against eastern generators and other resources; it is not even-handed at all. Political and economic motives should not be permitted to interfere in the engineering. As I say in my courses, "When the Laws of Physics and the Laws of Economics collide, Physics wins."

Q. DID THE APPLICANTS CONSIDER SUFFICIENT ALTERNATIVES TO PATH?

A. The testimony of the applicants' witnesses indicates that the only alternatives seriously considered during the 2007 RTEP were other AC EHV transmission lines. No alternatives involving non-transmission resources (generation, additional DSM, etc.) in the East, close to the load centers, were examined, even though they might offer distinct advantages in terms of cost, reliability, and environmental impact. Little recognition seems to have been paid to PJM's Reliability Pricing Model (RPM) process – despite the fact that one of its stated purposes is to provide incentives for generators to locate near the eastern load centers. PJM argues that it is not permitted to *order* anything other than transmission – but it certainly could develop policies that would *encourage* non-transmission solutions. Eastern resources seem to rate second-class status as compared to AC EHV transmission. No attention was even paid to transmission alternatives other than alternating current (AC) 500 and 765kV. High Voltage Direct Current (HVDC) alternatives were totally ignored in 2007 – despite HVDC's obvious advantages, and its utilization for other projects in PJM (e.g. Neptune and MAPP). PJM's planning process seems to be wearing blinders – any alleged reliability problems will be addressed by the "same old same old" EHV transmission solutions.

Somewhat belatedly, a "PATH HVDC Conceptual Study" has been initiated. Since this was not mentioned in any of the witnesses' testimony, we can safely conclude that HVDC was not considered as an alternative while the PATH studies were being conducted, and not evaluated at the time the decision was made to recommend PATH as a 765kV, AC project.

In addition, PJM's 2009 "re-tool" cases came up with different limiting elements than those relied on for the "need" assessment. These were generally on lower voltage facilities, and occurred further out in time. These differences alone should have suggested that other alternatives need to be explored. But they did not. In brief, the need for PATH was based on problems that no longer exist.

Q. WOULD YOU COMMENT ON PJM'S ONE-AT-A-TIME TRANSMISSION PLANNING?

A. I would describe PJM's approach to solving its alleged reliability problems as a piecemeal one. In recent years, we've witnessed a succession of proposals to build EHV transmission projects in PJM, each designed to solve a list of alleged reliability violations. It seems that no attempt is made to address the problems on an overall, integrated basis. Once a project is approved, it becomes cast in concrete. We're told it will take care of everything. Until the next one, that is. There never seems to be an attempt to look at what combination of solutions could solve *all* reliability problems/violations with a single overall solution or a set of integrated solutions. Nor does there appear to be any attempt to examine whether a new proposal, perhaps with some modifications, might obviate the need for one already approved.

It seems to me common sense that planning on a piecemeal basis will inevitably result in more facilities being built than would really be necessary to meet the requirements of NERC and other reliability standards. Perhaps a simple, hypothetical example will make this more understandable.

Let's assume that a planning entity follows a "piecemeal" approach. It studies its system, identifies certain reliability violations, and determines that a particular new facility would solve them. Let's assume it gains approval for that facility, and adds that facility to its base assumptions. It then begins another reliability study, and discovers another set of violations. A second facility is planned to fix these violations – it's also approved, and added to the base. A third study is conducted, and a third set of violations appears – and a third facility is identified and added to the base system. And so on through, let's say, seven studies and seven facilities. Is it not common sense that, had the planners looked at the *entire* system, and identified *all* reliability violations, they would almost certainly have been able to develop an "integrated," multi-facility solution which included *fewer* required elements than the earlier, piecemeal approach? A piecemeal approach is neither the best nor most efficient way to plan a system – more facilities will invariably be found to be "needed" than truly would be. That's because the second (or third or fourth) facility may prove to be an efficacious solution to the problems which drove the need for the first (or second or third). The net result will be an overbuilt system, with all the attendant economic, social and environmental consequences.

This bias or tendency toward "piecemeal," one-at-a-time transmission planning is a grave weakness of the current RTEP process in PJM.

Further, the piecemeal, cast-in-concrete approach forecloses other options. Each new facility goes into all the models, and is assumed in place for all the capacity auctions. Even the possibility of delay or cancellation is ignored. If *uncertainty* is viewed as an important factor for the representation of new generating units, it should also be included for proposed transmission additions.

There's another problem here. Once PJM, acting as the RTO, has identified one or more violations, it goes to the appropriate transmission owners (TOs) in whose systems the violations occur and in effect orders them to develop a solution. This kind of Balkanization does not serve the interests of overall reliability with minimum expenditure for new facilities. It's essentially a corollary to piecemeal, one-at-a-time planning. It seems to me that PJM should be more involved in developing overall solutions – and taking a second look at prior solutions, too.

Q. WOULD ADDING TRANSMISSION CAPACITY INTO THE EASTERN LOAD CENTERS MAKE THEM MORE RELIABLE?

A. No. Not if the added transmission results in the load centers being more dependent on remote generation. The more Philadelphia, Baltimore, Washington and Richmond must depend on long distance transmission, the more vulnerable they will be. And lower reliability is an inescapable consequence of greater vulnerability.

A further note. PJM seems to want to build a transmission system capable of delivering every MW from any generator anywhere on the system to any load point in PJM – regardless of reliability need or system conditions at the time. But that's not necessary for a reliable, or even an economically optimum system. On a reliability basis, comparable plans or options would include sufficient transmission capability to maintain an appropriate Loss of Load Expectation overall.

PJM could use Loss of Load Expectation techniques to compare generating capacity and other resources sited close to the load vs. less expensive generation more remote from the load, including the constraints of the intervening transmission system. Economic analyses would consider combinations of greater or lesser percentages of remote and local generation. However, the cost of necessary new transmission, plus incremental system losses, should be included. These costs would, of course, be much higher for remote generation, which would tend to offset any economic advantage it might otherwise have. Yet neither the applicants nor PJM has conducted any such analysis.

Q. IS PATH, IN YOUR OPINION, REALLY ABOUT RELIABILITY?

A. No. PATH is more about economics than reliability. When added to the present import capability in excess of 6,000MW, there is more than enough generating capacity within the constrained Mid-Atlantic LDA to supply all the load all the time. Thus there is no reliability need to increase the import capability by about 2,000MW – from 6,240MW to 8,190MW. This would involve operating more expensive, local generation more frequently; however, reliability would be enhanced, since the Mid-Atlantic LDA would be less dependent on generating capacity hundreds of miles away. Such an approach is called “transmission constrained dispatch,” or the use of “out of merit” generation, and is consistent with how the system is actually operated. It’s commonly used by most power systems in North America in both planning and operations. It would reduce the chance of widespread interruption, whether from human error, equipment failure, *force majeure*, or terrorist attack. Any increase in generation costs would be offset by savings in transmission construction, at least in part. Finally, and perhaps most important, this case is supposed to be about *reliability*, not *economics*.

In my opinion, PATH isn’t just about economics *in general* – it’s about *coal-fired* economics. This is clearly illustrated by a presentation made by Mr. Karl Pfirrmann at a FERC Technical conference on May 13, 2005. At the time, he served as President, PJM Interconnection, L.L.C., Western Region. In his Executive Summary, Mr. Pfirrmann describes “the potential for new transmission resources in the region to enhance opportunities for coal based generation to reach eastern markets.” The proposal is called Project Mountaineer, and includes “potentially 550 to 900 miles of new backbone 500 or 765 kV transmission at an approximate cost of $3.3 to $3.9 billion.” In his written comments, Pfirrmann describes this as a "new initiative … to utilize our regional transmission planning process to explore ways to further develop an efficient *transmission 'super-highway' to bring low cost coal resources to market*." [Emphasis added.] Mr. Pfirrmann also hails "dramatic increases in the amount of power flowing from this region into 'classic' PJM, including from coal-based generation," and offers an exhibit illustrating a 35-40% increase since PJM's expansion to the west.

We can gain some perspective on this by considering PATH's predecessor. An EHV line from Amos to eastern PJM was proposed before any "violations" had been indicated. This was in connection with Project Mountaineer, as discussed above. As suggested by Mr. Pfirrmann, Project Mountaineer's original goal was to provide access to eastern markets for an additional 5,000MW of western generation. The TrAIL and PATH projects, taken together, are remarkably consistent with such an intent. Some might ask, if PATH is approved, what will be next?

Q. WHAT IS YOUR VIEW OF THE VOLTAGE STABILITY PROBLEMS CITED BY MR. McGLYNN?

A. PJM has not proven that the alleged "voltage instability" is a legitimate problem. Mr. McGlynn goes to considerable length to establish voltage instability, but his only evidence – so-called "knee-of-the-curve" analyses – is incomplete. No transient stability results have been shown. "Knee-of-the-curve" analysis is useful as a screening tool, but voltage instability can only be proven by rotor-angle stability analysis in which the dynamic response of the overall system to a sudden disturbance is simulated in the time domain. Neither the applicants nor PJM have presented any such stability results. And all of the cited violations occur at CETO values that I consider to be unnecessarily high. Mr. McGlynn's testimony confirms that there are no voltage issues until transfers into the Mid-Atlantic LDA are well above 6,000MW.

Q. WHAT ABOUT STEADY STATE VOLTAGES, BOTH ABSOLUTE VOLTAGES AND VOLTAGE DROP?

A. Whatever voltage problems may exist might be solved by power factor correction. Low voltage problems, whether on an absolute or a voltage drop basis, are generally an indication that reactive (MVAR) loads are too high relative to active (MW) loads. This is reflected by low power factors – i.e. the ratio of MW to MVA. Reactive (MVAR) load is a natural part of power system load, and comes from various apparatus on customers' premises. It can be reduced by the installation of shunt capacitors or static VAR compensators (SVCs), which supply reactive power. Failure to adequately compensate for reactive load means higher MVAR loads as seen from 115kV and 138kV substations, hence lower power factors. Basically, what happens is that the high reactive loads have to be supplied from remote generators and the EHV system, essentially dragging MVARs through all the impedances of the various transmission lines and transformers. This results in larger voltage drops. [A close approximation of voltage drop can be determined by multiplying the per-unit inductive reactance of a line or transformer times the per-unit MVAR flow through it.] Further, the higher power flows through all the lines and transformers will result in higher reactive (MVAR) I^2X losses, and the consequent need to pull even more reactive power off the EHV system, which leads to larger voltage drops, etc. This phenomenon will only get worse as load grows. The best place to correct power factor is to place shunt capacitors on the subtransmission and distribution system – as close to the load as possible.

Many of the Mid-Atlantic buses listed in PATH's response to SierraVA-IV-51 have power factors below 95% – despite the fact that PJM Manual 14B, Appendix D: "PJM Reliability Planning Criteria" calls for a minimum power factors of 97%.

Power factor correction is in essence a reduction in reactive (MVAR) load, generally by adding shunt capacitors on the distribution and/or subtransmission systems. If this is impractical for some reason, shunt capacitors can be added at 115 and 138kV substation. If for any reason even *that* is impractical, the applicants themselves have suggested the solution – shunt capacitor or SVC additions at higher voltage stations.

Power factor correction (reactive compensation) is an ongoing process – it has to be continued year after year as system load grows. It's part of the continuing obligation of providing good utility service. The applicants do not seem to have examined if the voltage problems could be fixed by improving power factors. Nor have they examined the possibility of adding switchable shunt capacitors to some of the 115/138kV substations. We have been told that a "high level" investigation was made which considered adding shunt capacitors at 500kV and 230kV substations without PATH, and this was deemed to be too expensive. But applicants' witnesses in other states have testified that more than 1700MVAR of shunt capacitance will be required at both terminals of the proposed PATH line! (See Dr. Hyde Merrill's testimony.) In any case, no description of the nature of this "high level" investigation was provided. Without a presentation of the results of power factor and lower voltage substation studies, and an explanation of the reactive additions needed by PATH itself, the alleged voltage problems cannot be proven.

Q. PLEASE DESCRIBE SOME OF YOUR OVERALL IMPRESSIONS OF THIS CASE.

A. PJM and the applicants demonstrate a distinctly "one track mind" in their planning. Alternatives involving means other than an AC EHV transmission line have not been explored – this is true despite the fact that the problems discovered in the 2009 analyses depict dramatically different limiting facilities than those uncovered in 2008. In fact, the 2009 "re-tool" cases came up with a very different set of problems, were less severe, and occurred further out in the future. To most planning engineers, this would suggest that other possible solutions should be examined, but no such attempt has been made. This is especially true if the conclusions are the result of extrapolation. The original PATH proposal remains unchanged, and alternatives remain unexamined.

There's a built-in bias against any other approach; e.g. the way representation of new generators is handled strongly discourages serious consideration of non-transmission alternatives. Even in the area of transmission itself, no alternatives other than 500 and 765kV AC have been examined. A strong case can be made that no additional transmission is needed. But even if additional transmission *is* needed, why hasn't PJM considered building PATH as, for example, an HVDC line? Or why hasn't the conversion of an existing AC line (such as the Mt. Storm-Doubs 500kV line, as suggested by Mr. Merrill) been considered?

As pointed out by my colleague, Dr. Hyde Merrill, all conclusions beyond the study year of 2014 were based on extrapolation from 2014 results. It's almost inconceivable to me that the need for a major transmission facility, costing in the neighborhood of $2 billion, would be based on extrapolated results. Extrapolation is also inconsistent with NERC's requirements for long-term studies. As I indicated earlier, the purpose of long-term studies is to provide some indication of the nature and direction of future reliability problems, and to ensure that any recommended short-term solutions will be consistent with future needs. Extrapolation does not, in my view, satisfy that requirement.
AEP and its partners seem to have refused to "think outside the box." Perhaps PATH's emphasis on AC EHV transmission, and the effective subsidization of western generation, reflects the potential profits that could be made from transmission usage charges, as well as AEP's ownership of major significant western generating resources. A major facility like the PATH line should not be approved based on extrapolation.

To summarize:

• In my opinion, there's a major problem with PJM's present RTEP/CETO process of assessing reliability. The assumptions are too conservative, and lead to requirements beyond what would be needed for good reliability.

• PATH would discriminate against eastern generation and other potential resources, and promote western generation, by providing the latter with free access to eastern load centers – all at the expense of the rate-payers.

• Whereas the rest of the industry utilizes a loss of load expectation of one day in 10 years, PJM uses one day in 25 years to determine the import capability required by each Load Deliverability Area (LDA) – which can be quite large. The Mid-Atlantic LDA, for example, has a peak load in excess of 60,000MW. This makes it equal in size to the combined neighboring New York and New England ISOs. Assumptions more in line with the industry, rationalized to a reliability standard equivalent to that used by New York and New England, would result in a CETO which would be lower than the point at which the first reliability violations occur. In other words, there would be no NERC violations.

• Without this overly conservative approach, CETO values would be lower and there would be no NERC violations. Hence there is no demonstrated need for PATH.

• Reasonable alternatives, both non-transmission and even transmission, were not considered despite their potential advantages in terms of cost, reliability, and environmental impact. The applicants did not consider any reasonable alternatives based on the currently identified (April 2009) issues.

• By increasing the dependence of the eastern load centers on remote generators and transmission lines hundreds of miles long, PATH would actually lower reliability. This is the *real* reliability problem in PJM. Further, the increased reliance on very long transmission lines is a national security issue.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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Hearings of the Senate Energy and Natural Resources Committee
July 31, 2008

I wish to thank the members of the Energy and Natural Resources Committee for the privilege of speaking to you about several issues of great importance for the future of our nation, and of great concern to me personally. I especially want to express my thanks and appreciation to Senator Bingaman and Senator Dominici of my adopted state of New Mexico, and to Senator Casey of Pennsylvania – along with their staffs.

My name is George C. Loehr, and I'm an engineer with more than 45 years of experience in the electric power industry. My primary expertise is in bulk power transmission system planning and analysis, and electric power system reliability. I was deeply involved in various post-hoc studies following the major blackouts in 1965, 1977, and 2003.

I worked as Executive Director of the Northeast Power Coordinating Council (NPCC) from 1989 to 1997, and was very active in regional, national and international activities. I took early retirement from NPCC in 1997, and now do management consulting, appear as an expert witness, write, and teach a variety of courses on power systems.

I have been a Vice President and member of the Board of Directors of the American Education Institute (AEI), and a charter member of Power Engineers Supporting Truth (PEST). At present, I serve as Chair of the Executive Committee of the New York State Reliability Council (NYSRC), and as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC).

I hold an advanced degree in English Literature along with my Bachelors in Electrical Engineering, and have been deeply involved in the arts for most of my life; for example, I recently published my first novel, *Blackout*, available through <lulu.com>.

A one-page bio is appended to this statement.

The opinions I express in my testimony are entirely my own, and do not necessarily reflect the views of any of my employers or clients, past or present.

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Arguably, nothing is more critical to the future of the United States and its citizens than a reliable electric power system. It can be said without exaggeration that electricity is the bloodstream that sustains our nation and allows it to live and prosper. As the major blackouts of the past have demonstrated, any interruption to power supply adversely affects our economy, our safety and comfort, and our national security. And the most vulnerable part of our power supply is the high voltage bulk power system – the grid. However, it is not the only critical part of a reliable electric system.

Actually, there are three separate "grids" in the continental U.S. – four, if we consider Canada as well. The Eastern Interconnection is the largest, stretching from the Atlantic Coast roughly to eastern Montana, Wyoming, Colorado, and New Mexico. It includes the Canadian Maritime Provinces, as well as Ontario, Manitoba, and Saskatchewan. The Western Interconnection runs from there to the Pacific Coast, and includes the Canadian provinces of Alberta and British Columbia, as well as a small portion of the northern Baja in Mexico. The ERCOT Interconnection comprises approximately 85% of the state of Texas, and the Quebec Interconnection consists of that province in its entirety.

The passage of the Energy Policy Act of 2005 (EPAct) was heralded as a major step forward in improving the grid and reducing the likelihood of large blackouts. One drawback, however, is its almost exclusive focus on transmission. It does not address generating capacity sited close to the load centers, or demand side management programs. These strategies are often preferable to transmission as a means of improving overall system reliability. They have the added benefit of adding to the system's installed reserve margin. My own experience over the years has indicated that a certain minimum amount of capacity – in the neighborhood of 80% of the peak demand – must be located within a load center to provide voltage/reactive power support, black start capability, network security, etc.

If we wish to address electric power energy issues, we must address them in a more comprehensive manner. At present, the EPAct, and policies adopted thereunder, encourages the construction of new transmission not needed for reliability. It subsidizes remote generators, discriminates against local and distributed generation and demand side resources, forces many customers to pay for someone else's benefits, increases the likelihood of blackouts, and makes our grids more vulnerable to terrorist attack.

I believe that decisions on whether particular transmission lines are needed for reliability are best addressed by the states and by the eight existing regional reliability councils. They have consistently done a good job on this in the past. I do not believe that either DOE or FERC has the experienced staff or other resources to do this as well as the regional reliability councils and the states.

Since the passage of EPAct, some misguided proposals have been made to advance corporate agendas rather than serve the well-being of ordinary customers – mainly by trying to get proposed high voltage transmission lines approved as essential to reliability. The most significant are:

- The <u>confusion of reliability with economics</u> – of reliability *needs* with economic *wants*;

• The assumption that the mere addition of transmission will improve grid reliability. It won't. In fact, more transmission can actually degrade reliability if it is used to accommodate higher power transfers over long distances;

• The misapplication of national reliability standards promulgated by the North American Electric Reliability Corp. (NERC), the organization designated by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) mandated by EPAct;

• Blackout "scare tactics" intended to frighten customers and public officials, compelling them to endorse the construction of facilities or implementation of policies which are not required to preserve or enhance reliability.

Because of the confusion between economics and reliability, officials often commingle both inappropriately. A prime example is the 2006 Congestion Study conducted by the Department of Energy (DOE), as mandated by EPAct. [An updated 2009 Congestion Study is now under way.] As a result of its 2006 study, which did not properly consider non-transmission alternatives, the Department designated certain National Interest Electric Transmission Corridors where, according to DOE, consumers were adversely affected by transmission congestion or constraints. But the DOE's failure to properly consider non-transmission alternatives means that the congestion study has not even established economic congestion. In addition, congestion or constraints do not equal low reliability. Neither the 2006 study, nor the corridor designations, bear any resemblance to actual reliability problems. Economic *wants* were misrepresented as reliability *needs*. Reliability depends on standards, not the ability to move every megawatt from any generator anywhere on the system to any load center anywhere else on the system. Because the 2006 Congestion Study is fatally flawed, and does not draw a proper distinction between reliability and economics, it should not be used as the basis for approving new transmission lines that have been denied by the states.

In the deregulated electric power industry, the cost of new bulk power transmission facilities is often "socialized" if it can be shown that these facilities are needed to maintain reliability – to satisfy NERC reliability standards. "Socialization" means that the cost will be proportionally distributed among all customers within an Independent System Operator (ISO) or Regional Transmission Organization (RTO). If a reliability need cannot be proven, the cost will usually be assigned to those entities which will gain from the new facility. For example, if a new line is desired to allow the construction of new generating plants far removed from the load centers, and facilitate the transfer of their electrical output to the load centers, then clearly those generators will gain. But, if a reliability "need" could somehow be proven, the cost of the line would be borne by all customers in the region – an indirect but very real subsidy to the remote generators. Further, the skewing of costs and benefits would penalize resources located close to the load centers. It would also encourage the development of remote generating resources and discourage the development of more local or distributed generation, or demand side management programs.

The following points are generalizations derived from actual cases presented over the past several years.

In order to "prove" a reliability "need," some have misrepresented and misapplied the national reliability standards promulgated by NERC and supported by FERC. This misrepresentation sometimes involves ignoring key provisions of a national standard. For example, one of the key NERC planning standards calls for testing the system for the outage of a critical facility, allowing time for manual system readjustments to compensate for the outage, and then applying a second critical outage. The system must be designed to survive this sequence of events. However, some parties seem to have deliberately ignored the provision for manual system adjustments. This has the effect of greatly overstating the adverse consequences of the contingencies, in effect subjecting the system to two simultaneous contingencies. This, in turn, can indicate a failure to meet reliability standards – requiring a transmission reinforcement which is not really needed.

An even simpler example is the manipulation of generating units in the ISO or RTO queue in such a way that some committed units are excluded from planning studies. In some cases, units well along in the process have been deliberately excluded from studies because they would solve a reliability problem, while others *at the same place in the queue* were included, precisely because they exacerbate a reliability problem. In my opinion, this makes absolutely no sense.

Similarly, some have ignored readily available techniques permitted by the standards and widely utilized throughout the industry. They resist simple, straightforward fixes such as the addition of reactive power support, correction of minor limitations on lower voltage facilities, modification of outdated configurations, redispatch of generation, or manual load shedding following a contingency – all of which are permitted by the NERC standards and widely used in the industry.

Another device used by some to allege a reliability need when none really exists is to base system simulation studies on extreme conditions vis-à-vis generation dispatch. They will stubbornly insist on economic dispatch as a kind of mantra, ignoring the simple expedient of transmission constrained dispatch – using "out of merit" generation – to essentially replace less expensive remote generation with generation or demand side resources closer to the load, in effect working around any alleged transmission bottleneck by replacing remote generation with slightly higher-priced local resources. Many U.S. systems routinely operate in this manner. But some who are intent on "proving" a reliability need in their planning studies will refuse to make even minor adjustments to their initial dispatch in order to solve apparent reliability problems.

Those who misapply the reliability standards will often argue that NERC standards *require* that each ISO, RTO and transmission owner establish procedures that "stress" the transmission system in its planning studies. That's correct. But NERC standards do *not* require that the ISOs, RTOs and transmission owners use unrealistic base conditions, dismiss simple and obvious solutions to reliability problems, or ignore important provisions of the standards like manual system adjustments.

Some will maintain that the addition of new transmission facilities alone will inevitably increase reliability. This seems like common sense – but it's wrong. Addition of new transmission facilities will increase transfer capability, but reliability can only be improved by making the standards themselves more stringent. *Reliability is a function of the standards used, not the amount of wire in the air*. Further, transmission additions will not increase the reliability of the system if the increased transfer capability is used to accommodate increased power transfers. The same reliability standards would still be in place. The transmission transfer capabilities would be higher, but the higher transfer capability would simply be used to carry higher long-distance power flows.

There's another factor to consider. If more generation is built in remote areas, and less generation and other resources are built close to load centers, then the load centers will be increasingly dependent on distant generating capacity – located perhaps hundreds of miles away. It would be like running a long extension cord to a friend's house a block or two away to power your toaster, instead of plugging it into an electric outlet right in your own kitchen. The more major cities depend on long transmission lines, the more subject they will be to power outages and blackouts due to major contingencies on the transmission system. Indeed, this constitutes a national security problem, since these urban areas would be more at risk from terrorist attacks on transmission facilities.

Unfortunately, a lot of scare tactics have been used to justify proposed transmission lines. Perhaps the most egregious strategy used by those promoting new transmission when it really isn't needed for reliability involves raising the spectre of massive blackouts. The August 14, 2003 blackout has often been cited, for example. Even the California rotating blackouts of the 2000-2001 period have been mentioned. These incidents have *no bearing* on any of the cases I've seen. The 2003 blackout was the result of too many control areas (now known as "balancing authorities") in too small a geoelectrical area – so small, in fact, that none of them realized that a series of unrelated contingencies across a wide area over a four hour period was leading to a major interruption. In California in 2000-2001, poor state regulations, unscrupulous market manipulation, and unethical (sometimes illegal) activities by companies like Enron, all combined to manufacture an apparent shortage of generating capacity. No capacity shortage existed – nor was there a "blackout" *per se*. Brownouts and rotating feeder outages were necessary because of the market manipulation, but no widespread cascading outages occurred.

Let's think about how real-life systems would deal with situations involving overloaded transmission. System operators in real-time control centers act as balancing authorities over large geoelectrical areas, and would recognize any potential overload situation. More important, they would never operate the system in a mode where a first contingency would bring about overloads, low voltages, cascading outages, instability, system separation, or loss of firm customer load. That's the "Prime Directive" of every system operator. The bulk power system must always be operated such that, if any contingency specified in the applicable standards or criteria were to occur (e.g., a fault or short-circuit on a high voltage transmission line), the system would experience no overloads, low voltages, cascading outages, instability, system separations, or loss of firm customer load. In fact, to operate in any other way would be a violation or NERC's Operating Standards, subject to fines of up to $1 million per day.

Blackouts are usually caused by contingencies more severe than standards/criteria, by equipment failures, control system problems, human error, or by some combination of these. They always involve a break-up of the bulk power transmission system. Blackouts are not caused by shortages of generating capacity. Nor are they caused by an inability to transfer as much power as some might wish from remote locations to load centers. Blackouts can rarely be anticipated. They are almost always unexpected, and can happen at any time – few have occurred at or near peak load, for example, or coincident with a shortage of generating capacity. They develop in seconds or fractions of seconds rather than hours or days.

There's another important point. <u>The mere fact of adding transmission does not of itself increase reliability</u>. Consider two hypothetical transmission systems: one a system with a lot of transmission lines, but planned and operated to <u>less</u> stringent reliability standards; the other a system with very little transmission, but planned and operated to <u>more</u> stringent reliability standards. The first system would be less reliable than the second system, because it uses less stringent reliability standards. As I said earlier: *Reliability is a function of the standards used, not the amount of wire in the air*.

Even if both systems were planned and operated to the same reliability standards, the system with more transmission lines might still be less reliable than one with less. This is because the addition of new transmission lowers the equivalent electrical impedance across the grid, in effect making it electrically smaller. Thus a given contingency could have a more widespread effect. For example, if Philadelphia is electrically closer to Chicago, a major disturbance on the grid in the Chicago area is more likely to cause outages in Philadelphia – and *vice versa*. This may help explain why the Aug. 14, 2003 blackout affected a much larger area than the November 9, 1965 blackout.

Again, transmission additions will not increase the reliability of a system when the increased transfer capability is used to accommodate increased power transfers between remote generating units and load centers.

To ensure reliability of the bulk power system, Congress would need to comprehensively address electric power supply issues. Congress would need to encourage local power generation and distributed generation close to the demand, and create incentives for conservation and demand side resources. Any consideration of transmission issues should make a clear distinction between facilities needed for reliability and those desired for economic reasons. In particular, *economic wants* should not be permitted to camouflage themselves as *reliability needs*. Such an approach would help avoid blackouts, and make our grids less vulnerable to terrorist attacks.

However, as set forth above, I believe the states and the eight existing regional reliability councils are in the best position to ensure a reliable electrical grid.

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These are my major points. I would also like to briefly enumerate a few other problems I see, either on the horizon or already with us:

• The "deregulation" or "restructuring" of the electric power industry is part of the problem. In essence, it greatly increased the complexity of the power industry, and added thousands of pages of new regulations. (As a matter of fact, even the term "deregulation" itself is an Orwellian misstatement.) Most important, though, it replaced the former culture of *coordination and cooperation* with one of *competition and confrontation*.

• In some parts of the country, there are what I would term "overlapping footprints" among the various entities involved in the planning and operation of both the physical power system itself and its markets. This overlapping is a prescription for blackouts.

• Some control areas, or balancing authorities, are too small. As mentioned earlier, this was arguably the underlying cause of the August 14, 2003 blackout.

• The present growth rate of electric power demand and consumption is sometimes identified as the culprit. Actually, there's nothing exceptional about present growth rates. The *NERC 2006 Long-Term Reliability Assessment (October 2006)* reported a forecast U.S. annual growth rate for the period 2006-2015 of 1.9%. This is quite low by historical standards – for example, in the early 1960s, when I began my career, peak loads were growing nationally at a 7 to 7½% rate. That wasn't a short-term phenomenon, either. According to U.S. Energy Information Administration statistics, retail sales of electricity in 1970 were *five times higher* than in 1950 – a compound annual growth rate in excess of 7%. It doubled again between 1970 and 1990 – approximately a 3% growth rate – despite oil embargoes, hyper-inflation, recession, and conservation efforts. The only thing unusual about today's growth rate is that it's so low. This, I believe, reflects the efforts of many people – dedicated environmentalists, government officials at both the federal and state level, large commercial and industrial customers, and the general public – to achieve higher efficiencies and genuine conservation. We can all take credit for this significant accomplishment. Bottom line: nothing about current growth rates automatically requires a massive program of new transmission construction.

• People are often told that one "silver bullet" or another will solve all of our energy problems. Examples range from capacity auctions to mandatory standards, from renewable resources to the so-called "smart grid." While some of these may be valuable in their own right, none can be, as St. Paul might say, "All things to all men." Simply put, there is no silver bullet.

• Technical expertise – or at least competent, objective technical input – has become almost totally absent in decision making. Decisions are most often made on the basis of economic principles, with little or no consideration (or even knowledge) of the scientific laws that govern electric power systems. The Laws of Physics make electricity flow, not the Laws of Economics. No rules, no regulations or procedures, and no market protocols, can override Mother Nature and her laws. As I tell the students who take one of my courses or workshops: *When the Laws of Physics and the Laws of Economics collide, Physics wins … always*.

Where should we go from here? Frankly, I believe EPAct is in need of an overhaul. Congress needs to address energy issues – even those energy issues focused on electric power supply – in a more comprehensive manner. At present, EPAct encourages the siting of new transmission not needed for reliability. By doing so, it subsidizes remote generators, discriminates against local and distributed generation and demand side resources, forces many customers to pay for someone else's benefits, increases the likelihood of blackouts, and makes our grids more vulnerable to terrorist attack.

I would like to conclude with a favorite and well-known quote from the 18th Century Anglo-Irish author, philosopher and politician, Edmund Burke: "All that is necessary for the triumph of evil is for good men to do nothing." Let's resolve *not* to "do nothing," but let's be sure that, whatever we do, we do the *right* thing.

George C. Loehr – July 2008

George C. Loehr

[bio]

George C. Loehr received a Bachelor of Electrical Engineering degree from Manhattan College in 1962, and a Master of Arts in English Literature from New York University in 1964. He began his engineering career in transmission planning with the Consolidated Edison Company of New York in 1962, and completed the GE Power Systems Engineering Course in 1965. Following the 1965 Northeast Blackout, he was actively involved in a wide range of follow-up activities, and chaired the committee which completed a computer simulation of the event – the first such successful simulation of a wide-spread power failure in North America.

Loehr joined the New York Power Authority as Chief Planning Engineer in 1969, and the Northeast Power Coordinating Council (NPCC) in 1972. He was very active in regional, national and North American Electric Reliability Council (NERC) activities, serving on numerous committees, subcommittees and task forces. He was named Executive Director of NPCC in 1989, and remained in that position until his retirement in 1997.

Now self-employed, Mr. Loehr does management consulting, appears as an expert witness, writes, and teaches a variety of courses on power systems to non-technical professionals. His clients have included organizations throughout the U.S., Canada and China. He has served as Vice President and member of the Board of Directors of the American Education Institute (AEI), and is a charter member of Power Engineers Supporting Truth (PEST). Loehr is presently Chair and an Unaffiliated Member of the Executive Committee of the New York State Reliability Council, which works in conjunction with the New York ISO, and previously chaired its Reliability Compliance Monitoring Subcommittee. He also serves as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC). He is a recognized national expert on electric power system reliability.

Mr. Loehr has given expert testimony in the states of Pennsylvania, New York, Vermont, Kentucky, New Mexico, Mississippi, and in Washington, DC. He has done TV interviews with BBC, CNN, WPIX and CBC, and has been a lecturer, keynote speaker, and/or chair at professional conferences all over the U.S. and Canada. In addition, he has done audio tape lectures for various organizations, including the IEEE, "Professional Development Options," "Red Vector," and AEI.

Articles by Mr. Loehr have appeared widely in the trade press, including *Public Utilities Fortnightly, Electrical World, The Electricity Journal, Electricity Daily, Transmission & Distribution World, Energy Perspective, Restructuring Today, Energy Pulse, Natural Gas & Electricity, EnergyBiz,* and the Belgian magazine, *Revue E tijdschrift*. A recent op-ed piece was published in *The New York Times*. He is co-editor of and a contributor to the IEEE book, *The Evolution of Electric Power Transmission Under Deregulation*.

In addition to his engineering career, Mr. Loehr is a published author, has exhibited his art photographs at galleries in the New York metropolitan area, and has done stock photography for a world-wide photo agency. His photographs have appeared in numerous magazines, advertisements, business brochures, and several “coffee table” books, and one of his art photos was used as the cover for Sandra Brown’s best-selling novel, *Fat Tuesday*. He recently published his own first novel, *Blackout*.

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☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	3
Docket No.:	E002/CN-22-532 & E002/TL-23-157		
Response To:	Prehn Family and NoCapX 2020		
Requestor:	Carol A. Overland		
Date Received:	March 28, 2025		

Question:
When was the Prairie Island-Byron-Adams line first built and capacity at that time, expressed in MVA? When was it last updated and/or uprated, and what updates and/or uprates were made? What is the current capacity of that line, expressed in MVA?

Response:
Please see Table 1 below.

Table 1

	Prairie Island-Byron-Adams 345 kV			
First In Service Date	January 2, 1970			
Original rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	956.1	1192.1	1195.1	1195.1
Date of last uprate	N/A			
Description of upgrade	N/A			
Current rating (MVA)	SN (MVA)	SE(MVA)	WN(MVA)	WE(MVA)
	956.1	1192.1	1195.1	1195.1

Preparer:	Max McFee
Title:	Sr, Transmission Product
Department:	Integrated Transmission
Telephone:	612-330-6417
Date:	April 7, 2025

☐ **Not-Public Document – Not For Public Disclosure**
☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy Information Request No. 2
Docket No.: E002/CN-22-532 & E002/TL-23-157
Response To: Prehn Family and NoCapX 2020
Requestor: Carol A. Overland
Date Received: March 28, 2025

Question:
When was the King-Eau Claire-Arpin first built and capacity at that time, expressed in MVA? When was it last updated and/or uprated, and what updates and/or uprates were made? What is the current capacity of that line, expressed in MVA?

Response:
Please see Table 1 below.

Table 1

<table>
<tr><td></td><td colspan="4">King Eau Claire-Arpin 345kV</td></tr>
<tr><td>First In Service Date</td><td colspan="4">January 1, 1960</td></tr>
<tr><td rowspan="2">Original rating (MVA)</td><td>SN (MVA)</td><td>SE(MVA)</td><td>WN(MVA)</td><td>WE(MVA)</td></tr>
<tr><td>1188.5</td><td>1188.5</td><td>1195.1</td><td>1195.1</td></tr>
<tr><td>Date of last uprate</td><td colspan="4">N/A</td></tr>
<tr><td>Description of upgrade</td><td colspan="4">N/A</td></tr>
<tr><td rowspan="2">Current rating (MVA)</td><td>SN (MVA)</td><td>SE(MVA)</td><td>WN(MVA)</td><td>WE(MVA)</td></tr>
<tr><td>1191.5</td><td>1191.5</td><td>1195.1</td><td>1195.1</td></tr>
</table>

Preparer: Max McFee
Title: Sr, Transmission Product Modeling
Department: Integrated Transmission Planning
Telephone: 612-330-6417
Date: April 7, 2025