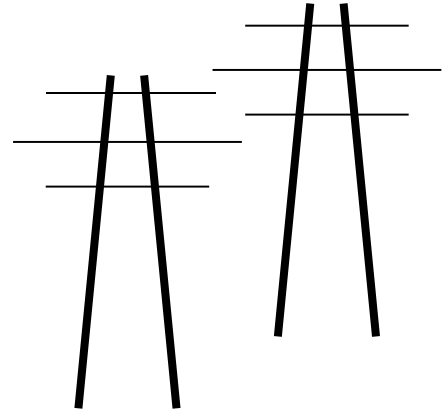


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April 25, 2025

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.

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. §216L.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 REGULATOR³

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

³ NoCapX and the Prehn Family seem to have struck a nerve with the assertion that "MISO IS NOT THE REGULATOR" 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:



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 Portfolio⁴ 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 paralleling, 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 Order⁵ 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

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

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: 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

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 Addendum¹²” 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 filing¹⁴, the peak of 2024:

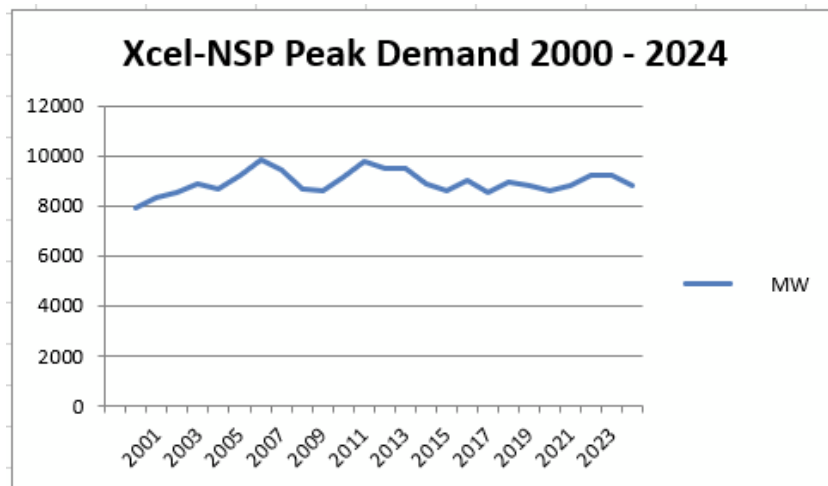
Capacity and Demand

Uninterrupted system peak demand and occurrence date:

Utility Subsidiary	2024		2023	
	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 Report¹⁵.

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://legalelectric.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://legalelectric.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 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
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. XCEL AND JOINT COMMENTERS TOUT CO2 REDUCTION BENEFITS, BUT HOW DOES TRANSMISSION LOWER CO2?

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 coal⁶⁸ 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's MTEP21 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-Arpin to the east. Both are old lines that have not been

rehabbed, not uprated or upgraded. As above, these lines are outdated, utilizing old and 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

Attorney for the Prehn Family and NoCapX 2020

**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 MN #254617
Attorney for NoCapX 202 and the Prehn
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(612) 227-8638
overland@legalelectric.org

**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
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**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

Attachment A_email thread between MISO Small and NoCapX/Prehn Overland

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@legalelectric.org>

Ms. Overland

Despite your 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@legalelectric.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:

Attachment A_email thread between MISO Small and NoCapX/Prehn Overland

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 <coverland@legalelectric.org>

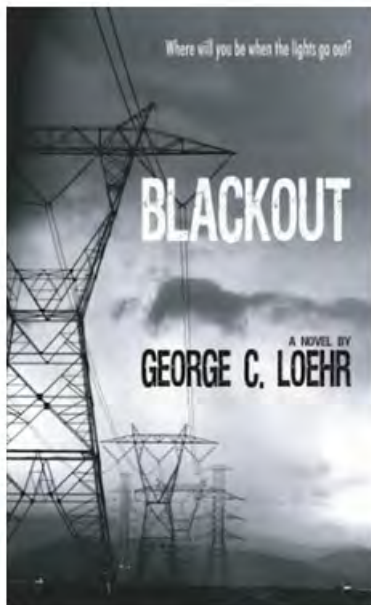
Sent: Monday, March 31, 2025 4:57 PM

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@legalelectric.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

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"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. Waiver Request

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,

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. Notice of Filing and Responsive Pleadings

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

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 County 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 Project¹⁵ 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 continue¹⁹ 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.

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

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

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

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

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.

Mark C. Christie
Chairman

George C. Loehr
eLucem

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TESTIMONY

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2

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

5

6 Q. BY WHOM ARE YOU EMPLOYED?

7

8 A. At present, I am self-employed.

9

10 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
11 PROFESSIONAL EXPERIENCE.

12

13 A. I received a Bachelor of Electrical Engineering degree from Manhattan College in
14 1962, and immediately began my engineering career with the Consolidated Edison
15 Company of New York, working in bulk power transmission planning. I also pursued
16 graduate studies at New York University, from which I received a Master of Arts in
17 English Literature in 1964. Also in 1964, Con Edison enrolled me in the General Electric

1 Power Systems Engineering Course (PSEC) in Schenectady, NY, which I completed in
2 1965. Following the 1965 Northeast Blackout, I was actively involved in a wide range of
3 follow-up activities. For example, I was Chairman of the Computer Committee, Federal
4 Power Commission System Studies Group, Interconnected System. My committee
5 completed an accurate computer simulation of the event – the first such successful
6 simulation of a widespread power failure in North America. I was later named Division
7 Engineer of Con Edison's Transmission Planning Division.

8
9 I joined the New York Power Authority (NYPA) as Chief Planning Engineer in 1969.
10 Up until that time, all of NYPA's system planning had been by consultants, and my first
11 assignment was to recruit and train a planning staff. I was responsible for management of
12 the planning staff and the conduct of all NYPA bulk power system generation and
13 transmission planning activities, which included load flow, transient stability, and loss of
14 load expectation studies. I also served on many New York Power Pool and Northeast
15 Power Coordinating Council committees and task forces.

16
17 I was hired by the Northeast Power Coordinating Council (NPCC) in 1972. Again, my
18 first assignment was to recruit and train a technical staff. My major responsibilities were
19 to manage the NPCC staff, which worked in support of the eight NPCC expert task
20 forces, and to advise NPCC's Joint Coordinating Committees and Executive Committee.
21 I became very active in regional, national and North American Electric Reliability
22 Council (NERC) activities, and served on numerous committees, subcommittees and task
23 forces. I also served on a Federal Power Commission advisory committee following the

1 1977 New York City Blackout. I was named Executive Director of NPCC in 1989, and
2 remained in that position until my (early) retirement in 1997.

3
4 Since retiring from the NPCC, I have done management consulting, appeared as an
5 expert witness, and taught a variety of courses on power systems – especially courses and
6 workshops for non-technical professionals. My clients have included organizations
7 throughout the U.S., Canada, and China.

8
9 At present, I am an Unaffiliated Member of the Executive Committee of the New York
10 State Reliability Council (NYSRC), and currently serve as its Chair; I formerly chaired
11 the NYSRC's Reliability Compliance Monitoring Subcommittee. In addition, I serve as
12 an Outside Director on the Board of Directors of the Georgia System Operations
13 Corporation (GSOC), and as a member of its Audit Committee. I have served as Vice
14 President and a member of the Board of Directors of the American Education Institute
15 (AEI), and I was a charter member of Power Engineers Supporting Truth (PEST).
16 I have given expert testimony in the states of Maine, Pennsylvania, New York, Vermont,
17 Kentucky, New Mexico, Mississippi, and in Washington, DC. I have done TV interviews
18 with BBC, CNN, WPIX and CBC, and have been a lecturer, keynote speaker, and/or
19 chair at professional conferences in the U.S. and Canada. In addition, I've made audio
20 tape lectures for various organizations, including the Institute of Electrical and
21 Electronics Engineers (IEEE), Professional Development Options, Red Vector, and AEI.
22 My articles have appeared widely in the trade press, including *Public Utilities*
23 *Fortnightly*, *Electrical World*, *The Electricity Journal*, *Electricity Daily*, *Transmission &*

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

7

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

14

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

17

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

1 the New York State Reliability Council Agreement and the New York Independent
2 System Operator/New York State Reliability Council Agreement.

3
4 Q. PLEASE EXPLAIN THE MISSION OF THE NORTHEAST POWER
5 COORDINATING COUNCIL (NPCC).

6
7 A. The Northeast Power Coordinating Council (NPCC) was the first of the Regional
8 Reliability Councils formed after the Northeast Blackout in 1965. Its role was (and is) to
9 ensure the reliability of electric power systems in the northeastern United States and
10 central and eastern Canada by developing, maintaining, and monitoring conformance
11 with reliability criteria for planning and operations. It also provides a forum for the
12 coordination of planning and operating procedures. NPCC's current membership
13 encompasses New York State, the six New England states, and the Canadian provinces of
14 Ontario, Quebec, New Brunswick, Nova Scotia, and Prince Edward Island. I might add
15 that the main reason I left the New York Power Authority and joined NPCC was my keen
16 interest in reliability and reliability criteria, and my wish to contribute toward making the
17 bulk power system more reliable.

18
19 Q. PLEASE EXPLAIN THE ORGANIZATION KNOWN AS POWER ENGINEERS
20 SUPPORTING TRUTH (PEST).

21
22 A. Following the August 14, 2003 blackout, several associates and myself, each with 40
23 years or more experience in electric power system planning and reliability, decided to

1 form a group to bring out the truth about electric power system reliability. To this end,
2 we established a not-for-profit organization, which we called Power Engineers
3 Supporting Truth (PEST). As we stated in our *Principles*, which were issued in
4 September 2003, our intent was “to identify the best ways to make the bulk power
5 systems in the United States both more reliable and economic.” We published several
6 reports over the next few years, and made our reviews and recommendations available to
7 the general public, as well as to interested industry groups, government officials, and the
8 media.

9
10 Q. HAS THERE BEEN A COMMON THREAD TO YOUR TESTIMONY IN STATES
11 SUCH AS MAINE, PENNSYLVANIA, NEW YORK, VERMONT, KENTUCKY,
12 NEW MEXICO, AND MISSISSIPPI?

13
14 A. Yes. My expert testimony in the various states has focused on bulk power system
15 reliability. So have my TV and radio interviews, my articles in the trade press, and my
16 conversations with reporters and journalists.

17
18 Q. WHAT IS THE SUBJECT OF THE COURSES AND WORKSHOPS YOU NOW
19 TEACH?

20
21 A. Virtually all of my courses and workshops, my speeches and lectures, and my audio
22 tapes primarily address two subjects: how the interconnected bulk power system (or
23 “grid”) works, and the importance of keeping it reliable.

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

3

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

7

8 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY HERE?

9

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

14

15 Q. COULD YOU SUMMARIZE YOUR VIEWS?

16

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

21

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

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

5
6 • PATH would not improve reliability. Rather, by making eastern load centers
7 all the way from northern New Jersey to northern Virginia more dependent on
8 remote generation and transmission lines hundreds of miles in length, PATH
9 would *exacerbate* reliability.

10
11 • PATH would effectively provide a subsidy to existing and future western
12 generators – access to the lucrative eastern load centers without cost to
13 themselves. Conversely, the western subsidies would place eastern generators at
14 a significant disadvantage. This is a clear violation of FERC's "fair and non-
15 discriminatory" principle.

16
17 • PATH would encourage remote rather than local generation by providing
18 western generators with free transmission access to eastern load centers. Existing
19 coal-fired generators would be ramped up, and new coal-fired generators would
20 be encouraged to site in the west.

21
22 • PATH's approval now, before commitments need to be made for generators and
23 other resources, would be a strong incentive to increase the output of existing

1 coal-fired plants, and for developers to build western generation. It would be a
2 disincentive for developers to site future generation and other resources in the
3 East, where they're most needed.

4
5 • PJM planning studies represent future generators which have executed only a
6 Facilities Study Agreement (FSA) if they add to a reliability problem, but require
7 the next step, an Interconnection Services Agreement (ISA), if they contribute to a
8 solution. This is a clear case of bias, and violates FERC's "fair and non-
9 discriminatory" principle. More important, it does not make engineering sense.

10
11 • The applicants seem focused almost exclusively on AC EHV transmission.
12 Non-transmission alternatives, and even other transmission alternatives like
13 HVDC, have been ignored.

14
15 • PJM's one-at-a-time planning is a piecemeal approach to solving reliability
16 problems. PJM, as the RTO, needs to step up to the plate and start planning its
17 system on a coordinated, integrated basis.

18
19 • In my view, the Load Deliverability procedure used by PJM comes up with
20 Capacity Emergency Transfer Objective (CETO) values that are unnecessarily
21 high, and seems out of synch with what the rest of the industry is doing. There
22 are better, more systematic and technically consistent ways to determine the

1 import capabilities required by Load Deliverability Areas (LDAs) to maintain
2 reliability.

3

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

7

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

11

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

15

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

20

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

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

3

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

7

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

14

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

20

21 • Other than construction of the 765kV PATH line, solutions to the alleged steady
22 state voltage violations have not been addressed. Apparently, neither power

1 factor improvements by adding capacitors at the distribution and subtransmission
2 level, nor shunt capacitors at 115/138kV substations, have been considered.

3

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

7

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

11

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

17

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

22

23

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

3
4 A. Among the more important considerations when dealing with large power systems are
5 the reliability standards or criteria used for planning and operations. These have been an
6 integral part of the electric power industry since the very first systems were developed in
7 the late 19th Century, but they became increasingly important as power systems expanded
8 and merged to form what we now know as synchronous interconnections, or simply
9 “grids.”

10
11 Early “central station” systems were relatively simple. A major disturbance or
12 “contingency” could, at worst, shut down electric service in a small area – e.g., one
13 square mile. But the introduction of high voltage alternating current technology
14 permitted the use of long lines at higher voltage. This led to power systems which
15 spanned progressively larger areas. Also, systems found it advantageous to share
16 generating reserves, and minimize reliability risks from transmission problems, by
17 interconnecting with each other.

18
19 This process took place through most of the 20th Century until, by the early 1960s, power
20 systems in most of the U.S. and Canada had coalesced into four large synchronous
21 interconnections or “grids.” The largest of these, the Eastern Interconnection, stretches
22 from the Canadian Maritimes to Florida, and from the Atlantic Ocean roughly to eastern
23 Montana, Wyoming, Colorado and New Mexico. It encompasses all eastern, central and

1 prairie provinces of Canada except Quebec and Newfoundland. The Western
2 Interconnection runs from the Rockies to the Pacific Coast, and includes the Canadian
3 provinces of Alberta and British Columbia, as well as a small portion of the northern Baja
4 in Mexico. The ERCOT Interconnection comprises approximately 75% of the state of
5 Texas. Finally, the Quebec Interconnection consists of that province in its entirety.

6
7 Power system planning begins with today's system – electric system planners do not have
8 the option of throwing away last year's (or last decade's) thinking and starting over from
9 scratch. So the power system as it exists is the starting point. Along with that, planners
10 must begin with today's system demand levels, and predict or "forecast" how customer
11 actions will affect electric demand in the future. In the present "deregulated" or
12 "restructured" electric power industry, the ownership of generating resources in many
13 states is separate from the ownership of the bulk power transmission system. Generation
14 is also competitive – various companies vie with one another in an open market.

15
16 There are two aspects to effective reliability: "resource adequacy," having enough
17 generation and other resources to meet the customers' electrical demand; and
18 "transmission reliability," the ability of the transmission system to deliver the power and
19 withstand sudden contingencies without overloads, low voltages, instability, or loss of
20 customer load. To meet these twin goals, power systems must establish certain standards
21 for both planning and operations.

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

8
9 Transmission reliability is assessed on a deterministic basis. Transmission planning
10 standards or criteria specify a variety of specific disturbances or “contingencies” – the
11 bulk power system must be able to withstand any of these without adverse consequences.
12 Failures of the transmission system can lead to overloads, cascading outages, instability,
13 system separations – and total blackouts over widespread areas. They almost always
14 occur without warning, and can rarely be anticipated; hence, preventive actions, other
15 than scrupulous adherence to standards and criteria, generally are not possible.

16
17 Blackouts are usually caused by contingencies more severe than those specified in the
18 applicable standards or criteria, by equipment failures, control system problems, human
19 error, or some combination of these. They involve the break-up of the bulk power
20 transmission system. Blackouts are not caused by shortages of generating capacity.

21
22 During the first half of the 20th Century, individual power systems each developed and
23 applied their own planning criteria. By mid-century, however, with the dramatic growth

1 of synchronous interconnections and the increasing use of the system to transmit power
2 over long distances, the limitations of such an approach were becoming obvious. When
3 the Northeast Blackout of 1965 occurred, it was plain to see that a more coordinated
4 approach was necessary.

5
6 PJM, which had a much smaller footprint in 1965 than it has today, was already
7 functioning with a uniform set of criteria. The systems involved in the 1965 blackout
8 soon followed suit. Shortly after the blackout, they formed the Northeast Power
9 Coordinating Council (NPCC). Other utilities across North America also formed their
10 own regional reliability councils, which eventually encompassed most of the continent.

11
12 Each regional council established its own reliability criteria. Each also developed
13 procedures for assessing conformance. Individual systems and power pools sometimes
14 developed their own more detailed or more stringent criteria, but they were always
15 responsible for adherence to the regional criteria as a minimum.

16
17 The regional reliability councils formed the National Electric Reliability Council (NERC)
18 in 1968 to coordinate their activities nationally and develop overall reliability guidelines
19 for their collective systems. NERC has evolved over the years. As additional Canadian
20 systems became members, it became the North American Electric Reliability Council.

21 But the most dramatic changes occurred in the wake of the August 14, 2003
22 Midwest/Middle Atlantic blackout. The Energy Policy Act of 2005 (EPAct) directed
23 FERC to establish an Electric Reliability Organization (ERO). Its major role would be to

1 develop and enforce mandatory reliability standards for planning and operations. After a
2 period of study, FERC designated NERC as the ERO, and its name was changed to the
3 North American Electric Reliability Council Inc.

4
5 Today, NERC develops reliability standards, which must be approved by FERC. The
6 regional reliability councils may have their own criteria, but these must conform to
7 NERC's. As provided by EPAct, compliance with NERC standards is mandatory. ISOs,
8 RTOs and individual utilities, as well as all other market participants like generators and
9 power marketers, are members of the regional reliability councils and must comply with
10 both the regional criteria and NERC standards.

11
12 NERC planning standards require both short- and long-term studies. Any violations
13 discovered in the short-term analyses must be addressed with appropriate solutions. On
14 the other hand, the purpose of the long-term studies is to provide some indication of the
15 nature and direction of future reliability problems, and to ensure that any recommended
16 short-term solutions will be consistent with future needs.

17
18 Q. HOW ARE STANDARDS AND CRITERIA USED IN TRANSMISSION
19 PLANNING?

20
21 A. The first step in evaluating the potential reliability need for new facilities is to
22 investigate the existing transmission system for a chosen future year, with existing and
23 planned generating resources added, along with any transmission additions already

1 scheduled. First, power flow or “base load flow” cases are created, representing base
2 conditions – generally, peak loads under various generation scenarios. Then, new load
3 flow cases are run simulating a wide range of potential disturbances or contingencies.
4 The results of these contingency load flows will indicate where and to what extent the
5 existing system needs reinforcement. At this point, familiarity with the system and
6 engineering judgment will usually suggest potential solutions to the violations, and
7 typically several will be chosen for further scrutiny. The most successful enhancement
8 will be chosen, consistent with a parallel cost-effectiveness analysis. Finally, non-
9 transmission alternatives should also be identified and examined, and compared in terms
10 of cost, reliability, and environmental impact with the preferred transmission solution.

11
12 One of the key questions is how severe the contingencies should be. Over the past fifty
13 years, planning engineers have reached a consensus on what is commonly known as
14 “worst single contingency” design – a.k.a. “n-1.” This means that the system must be
15 able to survive the worst single event which could happen to the bulk power system.
16 Typically, this is the loss of a large generating unit, or a three-phase fault on a major
17 transmission line or autotransformer. But the devil, as is said, is in the details.

18
19 Current NERC standards allow the planning entity a degree of judgment. NERC’s TPL-
20 002 and TPL-003, for example, require that the pre-disturbance system be *stressed*;
21 however, the nature of the “stress” is not defined – despite several requests from
22 transmission companies for a more definitive interpretation. It’s up to the planning entity
23 to fill in the details.

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

10
11 Base conditions provide another example where the planning entity’s judgment is
12 required. This would include assumptions regarding appropriate load level, the handling
13 of proposed new generation, the potential retirement or older generating units, and the
14 dispatch of the overall system. Dispatch scenarios, which can be viewed as the bridge
15 between “adequacy” (sufficiency of resources) and “operating reliability” (transmission
16 reliability), are of particular interest. Generally, the best approach is to examine several
17 different dispatch scenarios – varying the components and applying the most serious
18 contingencies in each example.

19
20 Many planning entities today use a so-called “90/10” load forecast, as opposed to a
21 “50/50” forecast, as one of many ways to satisfy the NERC “critical system conditions”
22 requirement. This means that there is a 10% probability that the actual load will exceed
23 the forecast demand, and a 90% probability that the actual peak demand will be lower.

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

12
13 Q. ARE THE RELIABILITY STANDARDS MANDATED BY NERC?

14
15 A. For some time, NERC has developed reliability standards for planning and
16 operations. As a result of the Energy Policy Act of 2005 (EPAct), these are now
17 mandatory under federal law. The NERC planning standards define the contingencies
18 which the power system must be able to survive without significant adverse
19 consequences – overloads, low voltages, instability, system separations, or blackouts.
20 However, the NERC standards do *not* define the configuration of the system to which
21 these contingencies are applied, other than to say that the system must be stressed –
22 assumed base conditions must “cover critical system conditions and study years as
23 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

1 represented, which are neither credible nor reasonable. Therefore, neither are the
2 conclusions.

3

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

7

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

16

17 Q. DO YOU BELIEVE THE PATH VIOLATIONS ARE REASONABLE?

18

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

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

5
6 Overall, PJM's and applicants' procedures are overly conservative. They pile
7 conservative assumptions on top of conservative assumptions – beyond what, in my
8 opinion, is reasonable. In brief, they push the "conservative" envelope too far.

9
10 Q. PLEASE COMMENT ON THE USE OF "CAPACITY EMERGENCY TRANSFER
11 OBJECTIVE" BY PJM AND THE APPLICANTS.

12
13 A. For any defined Load Deliverability Area (LDA), PJM does a Loss of Load
14 Expectation (LOLE) study to determine the import capability necessary to maintain a
15 "one day in 25 years" LOLE. This is then called the Capacity Emergency Transfer
16 Objective (CETO) for that LDA. The CETO value is based, among other things, on the
17 load forecast. A mean or median schedule is developed for the LDA, using the same
18 probabilistic statistics as in the LOLE, to accommodate an import equal to the CETO.
19 Next, load flow cases are run at that value, simulating the various requirements of NERC
20 Planning Standards TPL-001, -002, and -003. If the existing transmission system results
21 in "violations" for any of these (A, B, and C), the planners conclude that a transmission
22 reinforcement is required. PJM maintains that they're only permitted to consider
23 transmission reinforcements.

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

5
6 Mr. McGlynn discusses the Mid-Atlantic LDA at some length in his testimony. He cites
7 the Mid-Atlantic LDA's CETO used in PJM's April 2009 modeling as 8,190MW
8 [McGlynn, page 28.]. In my opinion, the 8,000MW+ value he comes up with as the
9 CETO is breathtakingly (and unnecessarily) high. That's an awful lot of power to
10 transfer into eastern PJM from the West. It's a very large value to expect to export to *any*
11 single area – something like one MW for every eight MWs of peak load. One has to ask
12 if this is really a reliable way to supply a high percentage of the electric requirements of a
13 metropolitan area that stretches from northern New Jersey to northern Virginia. That
14 entire megalopolis would be subject to interruption by many and diverse causes, natural
15 and human, intentional as well as unintentional. The present import capability of the
16 Mid-Atlantic LDA is in excess of 6,000MW – a pretty high number itself. (Exhibit
17 PFM3 lists the most restrictive contingency at a Mid-Atlantic LDA import of 6,240MW.)
18 In other words, without PATH, it would still be possible to send more than of 6,000MW
19 into eastern PJM. According to the PATH response to SierraVA-IV-61, there is
20 67,635MW of generating capacity in the Mid-Atlantic LDA as of October 2009 – *right*
21 *now*. Given this amount of *existing* generating capacity, not even counting whatever
22 additional capacity will be added over the next five years, why isn't a 6,000MW CETO
23 enough? PJM should place greater emphasis on incenting new generation to locate

1 within the Mid-Atlantic LDA, which would provide greater reliability to the eastern load
2 centers.

3
4 In responding to the VASStaff-V-5 request for updated data on the Mid-Atlantic LDA,
5 PJM cited a lower peak load forecast for 2014, an 827MW increase in installed capacity,
6 and a lower CETO value – 7,720MW. This CETO reduction of 470MW further reduces
7 any alleged “need” for the PATH line.

8
9 PJM’s “one day in 25 years” standard – used to come up with the CETO number – is also
10 questionable. This is a conservative assumption, PJM admits – part of the need to
11 “stress” the system. To my knowledge, no other RTO or ISO uses a value this high.

12 Why shouldn’t PJM use “one day in 10 years,” like everyone else? By comparison, one
13 day in 25 years is a higher standard than that used by either ISO New England or the New
14 York ISO, each of which is only about half the size of the Mid-Atlantic LDA. And this is
15 on top of a 90/10 load representation, which would be expected to occur only once every
16 ten years. PJM seems to pile one conservative assumption on top of another.

17
18 In fact, I would question whether a criterion of “one day in 10 years” for all of PJM is
19 itself overly conservative, given the large size of the expanded PJM system. The New
20 England and New York ISOs each use an adequacy criterion of one day in 10 years, yet
21 each is approximately one-fourth the size (in MWs) of the PJM system. Standardized to
22 the PJM peak load, New England and New York at one day in 10 years would be
23 equivalent to *four* days in 10 years. New York and New England include metropolitan

1 areas at least as critical as PJM's; why should PJM use a much more conservative
2 reliability criterion? In my opinion, it would not be unreasonable for PJM to use a less
3 conservative criterion, more in keeping with its peak load relative to other ISO/RTOs like
4 the New York ISO and ISO New England. For example, just by changing from a
5 criterion of one day in 25 years to one day in 10 years for the Mid-Atlantic LDA, and
6 putting it on the same loss of load expectation basis as New York and New England, PJM
7 could lower the CETO for the Mid-Atlantic LDA by approximately 3,000MW.

8
9 There are other, and in my opinion better, ways to do this kind of analysis. For example,
10 when it studies the LOLE of the entire PJM system to calculate the required installed
11 reserve margin, PJM uses a multi-area probabilistic program. It does not model separate
12 areas within PJM, however. PJM could use the same program to model all the LDAs
13 along with the existing transmission transfer capabilities between them, and still target an
14 overall LOLE criterion. A need to increase any of the inter-area transfer capabilities
15 would be evident from such an analysis. Thus PJM could unify the process, and also
16 meet the desired objective vis-à-vis the overall PJM system.

17
18 In fact, PJM's process for addressing reliability "need" is far more conservative than
19 necessary. In an earlier case (the proposed Prexy facilities in southwestern
20 Pennsylvania), this overly conservative approach led to a recommendation for a major
21 new 500kV transmission line, which was approved by PJM. In my opinion, such a high
22 voltage facility was clearly unnecessary, and I testified to this during the proceedings.
23 After the state hearings were mostly concluded, the PUC ordered a voluntary

1 collaborative effort. This led to a much simpler, less expensive, and less environmentally
2 intrusive solution involving modifications to the local 138kV system and the addition of
3 shunt capacitors.

4
5 The proposed Prexy Facilities were to consist of a new 500kV substation in Washington
6 County called "Prexy", a new 500kV transmission line (36 miles long) in Washington
7 and Greene counties, and three new 138kV lines (running 15 miles) to connect the
8 proposed new substation to the existing transmission system. After the collaborative
9 process, the approved fix reinforced the electric grid without any new 500 kV lines,
10 substations, or 138 kV lines. Instead, it involved installing one new monopole on an
11 existing utility right of way (to allow the connection of two existing lines), adding
12 equipment (capacitors) at five existing substations, and replacing the conductors on 2.5
13 miles of existing 138 kV lines. The estimated cost for the agreed-upon fix is \$11.6
14 million, instead of \$213 million for the proposed Prexy Facilities. And the
15 solution solved the same reliability issues that were "driving the need" for the previously
16 proposed "Prexy Facilities."

17
18 PJM's approval of the need for Prexy facilities, and PATH in this proceeding, violated an
19 engineering principle which a former professor of mine used to insist on: "Don't use a
20 pile driver to hammer tacks."

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

3

4 A. Not at all. Whether or not violations will occur ultimately depends on the value
5 selected for the CETO. This applies to voltage as well as line loading violations. There
6 would be *no* violations of NERC Standards if realistic CETO values were used. The only
7 reason that “violations” were identified in PJM’s studies is that PJM was trying to cram
8 too much power from outside (essentially western PJM) into the eastern LDAs by using
9 unnecessarily high CETO values. It’s sort of like a mouse trying to swallow a lion. For
10 the Mid-Atlantic LDA, without PATH, a 6,000MW CETO would result in zero
11 violations. Zero. And the Mid-Atlantic area would still be capable of importing over
12 6,000MW.

13

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

17

18 In my opinion, PJM faces a reliability problem – a *serious* reliability problem – which
19 will worsen if PATH is built. It’s the overdependence of the eastern PJM load centers on
20 generating units hundreds of miles to the west. The megalopolis from northern New
21 Jersey to northern Virginia is over-dependent on long transmission lines, any one of
22 which could be taken out of service by natural or human agents. This is a *major* problem
23 that needs to be addressed. And it’s a *national security problem* as well. PJM should, in

1 my opinion, develop a program to address this problem as soon as possible – but instead
2 PJM is pursuing policies that will only make the problem worse.

3

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

5

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

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

7
8 Now consider what happens when transmission is added. The apparent electrical
9 impedance across the grid is reduced, in effect making it electrically tighter. Thus a
10 given contingency could have a more widespread effect. By increasing the amount of
11 west-to-east transmission in PJM, the proposed PATH line would make the Eastern
12 Interconnection subject to larger blackouts.

13
14 This can be visualized in a more technical light. The key factor in the stability of a
15 system is the electrical angle between generators. Building transmission lines reduces the
16 equivalent electrical impedance between generators – the units become electrically
17 closer, and the angle is decreased, which tends to make the system more stable.

18 However, stability will be improved *only if no additional power is scheduled across the*
19 *system*. If the power flow is increased, then the angle is increased, and the units will be
20 electrically further apart, making the system less stable. My own experience after doing
21 this kind of analysis since the early 1960s is that, even if the impedance is decreased and
22 the power flow increased such that the electrical angles are the same, the system will still
23 be more vulnerable to extreme emergency contingencies – those that are more severe

1 than the criteria used in planning and operations, and which are either the major cause or
2 an important contributing cause of nearly all bulk power system blackouts.

3
4 When systems build more transmission only to accommodate higher levels of transfer,
5 they push the system harder. The likelihood of instability is increased; the system is
6 more likely to suffer a blackout if an unforeseen contingency occurs, and the blackout is
7 likely to be larger and more damaging. In my opinion, PJM has not proven a reliability
8 problem that requires the construction of PATH, or that PATH will make the overall
9 system more reliable. However, instead of building the PATH line, reliability could be
10 *improved* by promoting additional generating capacity and other resources in the East,
11 close to the load centers. Lower west-to-east transfers across the PJM system would
12 significantly reduce the angle between generators, making the northeast quadrant of the
13 Eastern interconnection less susceptible to instability and blackouts.

14
15 Q. DO YOU THINK THAT PJM PLACES TOO MUCH EMPHASIS ON EXTRA
16 HIGH VOLTAGE (EHV) TRANSMISSION LINES?

17
18 A. Very definitely. PJM seems to see EHV AC transmission not as the *best* solution to
19 reliability problems, but as the *only* solution. Under the current PJM cost allocation
20 rules, all transmission facilities at 500kV and higher are “socialized” – i.e. their costs are
21 charged to all the Load Serving Entities (LSEs) in PJM essentially in proportion to their
22 electric loads. This means that all customers throughout the PJM area will pay the
23 construction costs for PATH. Because of this “socialization,” PATH will provide

1 existing and future western generators, including coal-fired generators, with free access
2 to the eastern load centers. In effect, western generators will be subsidized at the expense
3 of the ratepayers. It's also a case of discrimination against generators and other resource
4 providers in the East.

5
6 In other words, western generators will be given market access to eastern load centers
7 without having to pay the cost of providing that access. Customers throughout PJM will
8 bear the full cost of the new transmission. Western generators, both existing and future,
9 will be able to compete with eastern resources without paying for the transmission that
10 makes it possible. This will skew the economics of electric generation supply by
11 subsidizing some generators at the expense of others – and ultimately at the expense of
12 ratepayers. This is not the “fair and non-discriminatory” market that FERC envisaged in
13 promoting “deregulation.”

14
15 Q. IT HAS BEEN SAID THAT TRANSMISSION PROJECTS MUST BE APPROVED
16 EARLY ON, SINCE THEIR LEAD TIMES ARE NOW LONGER THAN LEAD
17 TIMES FOR GENERATORS.

18
19 A. That's true, but early approval of transmission has another, unanticipated
20 consequence. Transmission lead times are now longer than the lead times for generators.
21 That means that transmission projects will generally be approved before generators or
22 other resource providers need to make their commitments. In other words, generating
23 companies can wait until a major transmission line is approved or disapproved before

1 deciding whether to build new generating units in the East or West. If a new line is not
2 planned, or a proposed line isn't approved, developers could site new units in the East,
3 where long EHV lines would not be required to reach load centers. On the other hand, if
4 a line *is* approved, developers are likely to build in the West, where it would be less
5 expensive, since they will be provided transmission access to the eastern load centers at
6 no cost to themselves.

7
8 Such transmission approvals would foreclose other options, including generators sited in
9 the East, load management systems, and greater reliance on Reliability Pricing Model
10 (RPM) solutions in general.

11
12 In summary, PATH would provide a strong disincentive to anyone considering locating
13 generation or other resources in eastern PJM, and a correspondingly strong incentive to
14 build coal-fired generation in western PJM. The seeming obsession with transmission
15 solutions will not only provide an effective subsidy to existing generators in the West, but
16 it will act as a magnet for siting future generators there, as opposed to locating in the
17 East, where they are really needed.

18
19 Q. ARE THERE ANY OTHER EXAMPLES OF DISCRIMINATION IN THE
20 ASSUMPTIONS UNDERLYING THE PATH STUDIES?

21
22 A. Yes. To me, an egregious example of PJM's discrimination is how the representation
23 of planned, future generators is handled. In its planning studies, PJM represents only

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

13
14 In my opinion, no distinction should be made. Any generator which has an executed
15 FSA should be represented, regardless of whether it exacerbates or solves reliability
16 problems. To intentionally discriminate against the very generators which could solve
17 reliability problems is both foolish and potentially costly. It goes against one of the most
18 important principles of FERC and deregulation – that all generators must be treated in a
19 manner that is both fair and non-discriminatory. Finally, again in my opinion, it
20 represents very poor engineering. Good engineering is premised on even-handedness –
21 PJM's biased handling of future generators, based on whether each would contribute to a
22 problem or its solution, tilts the science toward a presumably desired conclusion which
23 might not be proven by a fair and non-discriminatory approach. This constitutes a bias

1 towards transmission and in favor of western coal-fired generators and against eastern
2 generators and other resources; it is not even-handed at all. Political and economic
3 motives should not be permitted to interfere in the engineering. As I say in my courses,
4 “When the Laws of Physics and the Laws of Economics collide, Physics wins.”
5

6 Q. DID THE APPLICANTS CONSIDER SUFFICIENT ALTERNATIVES TO PATH?
7

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

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

6
7 In addition, PJM’s 2009 “re-tool” cases came up with different limiting elements than
8 those relied on for the “need” assessment. These were generally on lower voltage
9 facilities, and occurred further out in time. These differences alone should have
10 suggested that other alternatives need to be explored. But they did not. In brief, the need
11 for PATH was based on problems that no longer exist.

12
13 Q. WOULD YOU COMMENT ON PJM’S ONE-AT-A-TIME TRANSMISSION
14 PLANNING?

15
16 A. I would describe PJM’s approach to solving its alleged reliability problems as a
17 piecemeal one. In recent years, we’ve witnessed a succession of proposals to build EHV
18 transmission projects in PJM, each designed to solve a list of alleged reliability
19 violations. It seems that no attempt is made to address the problems on an overall,
20 integrated basis. Once a project is approved, it becomes cast in concrete. We’re told it
21 will take care of everything. Until the next one, that is. There never seems to be an
22 attempt to look at what combination of solutions could solve *all* reliability
23 problems/violations with a single overall solution or a set of integrated solutions. Nor

1 does there appear to be any attempt to examine whether a new proposal, perhaps with
2 some modifications, might obviate the need for one already approved.

3
4 It seems to me common sense that planning on a piecemeal basis will inevitably result in
5 more facilities being built than would really be necessary to meet the requirements of
6 NERC and other reliability standards. Perhaps a simple, hypothetical example will make
7 this more understandable.

8
9 Let's assume that a planning entity follows a "piecemeal" approach. It studies its system,
10 identifies certain reliability violations, and determines that a particular new facility would
11 solve them. Let's assume it gains approval for that facility, and adds that facility to its
12 base assumptions. It then begins another reliability study, and discovers another set of
13 violations. A second facility is planned to fix these violations – it's also approved, and
14 added to the base. A third study is conducted, and a third set of violations appears – and
15 a third facility is identified and added to the base system. And so on through, let's say,
16 seven studies and seven facilities. Is it not common sense that, had the planners looked at
17 the *entire* system, and identified *all* reliability violations, they would almost certainly
18 have been able to develop an "integrated," multi-facility solution which included *fewer*
19 required elements than the earlier, piecemeal approach? A piecemeal approach is neither
20 the best nor most efficient way to plan a system – more facilities will invariably be found
21 to be "needed" than truly would be. That's because the second (or third or fourth) facility
22 may prove to be an efficacious solution to the problems which drove the need for the first

1 (or second or third). The net result will be an overbuilt system, with all the attendant
2 economic, social and environmental consequences.

3
4 This bias or tendency toward “piecemeal,” one-at-a-time transmission planning is a grave
5 weakness of the current RTEP process in PJM.

6
7 Further, the piecemeal, cast-in-concrete approach forecloses other options. Each new
8 facility goes into all the models, and is assumed in place for all the capacity auctions.
9 Even the possibility of delay or cancellation is ignored. If *uncertainty* is viewed as an
10 important factor for the representation of new generating units, it should also be included
11 for proposed transmission additions.

12
13 There’s another problem here. Once PJM, acting as the RTO, has identified one or more
14 violations, it goes to the appropriate transmission owners (TOs) in whose systems the
15 violations occur and in effect orders them to develop a solution. This kind of
16 Balkanization does not serve the interests of overall reliability with minimum expenditure
17 for new facilities. It’s essentially a corollary to piecemeal, one-at-a-time planning. It
18 seems to me that PJM should be more involved in developing overall solutions – and
19 taking a second look at prior solutions, too.

20
21 Q. WOULD ADDING TRANSMISSION CAPACITY INTO THE EASTERN LOAD
22 CENTERS MAKE THEM MORE RELIABLE?

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

5
6 A further note. PJM seems to want to build a transmission system capable of delivering
7 every MW from any generator anywhere on the system to any load point in PJM –
8 regardless of reliability need or system conditions at the time. But that's not necessary
9 for a reliable, or even an economically optimum system. On a reliability basis,
10 comparable plans or options would include sufficient transmission capability to maintain
11 an appropriate Loss of Load Expectation overall.

12
13 PJM could use Loss of Load Expectation techniques to compare generating capacity and
14 other resources sited close to the load vs. less expensive generation more remote from the
15 load, including the constraints of the intervening transmission system. Economic
16 analyses would consider combinations of greater or lesser percentages of remote and
17 local generation. However, the cost of necessary new transmission, plus incremental
18 system losses, should be included. These costs would, of course, be much higher for
19 remote generation, which would tend to offset any economic advantage it might
20 otherwise have. Yet neither the applicants nor PJM has conducted any such analysis.

21
22 Q. IS PATH, IN YOUR OPINION, REALLY ABOUT RELIABILITY?

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

15
16 In my opinion, PATH isn’t just about economics *in general* – it’s about *coal-fired*
17 economics. This is clearly illustrated by a presentation made by Mr. Karl Pfirrmann at a
18 FERC Technical conference on May 13, 2005. At the time, he served as President, PJM
19 Interconnection, L.L.C., Western Region. In his Executive Summary, Mr. Pfirrmann
20 describes “the potential for new transmission resources in the region to enhance
21 opportunities for coal based generation to reach eastern markets.” The proposal is called
22 Project Mountaineer, and includes “potentially 550 to 900 miles of new backbone 500 or
23 765 kV transmission at an approximate cost of \$3.3 to \$3.9 billion.” In his written

1 comments, Pfirrmann describes this as a “new initiative ... to utilize our regional
2 transmission planning process to explore ways to further develop an efficient
3 *transmission ‘super-highway’ to bring low cost coal resources to market.*” [Emphasis
4 added.] Mr. Pfirrmann also hails “dramatic increases in the amount of power flowing
5 from this region into ‘classic’ PJM, including from coal-based generation,” and offers an
6 exhibit illustrating a 35-40% increase since PJM’s expansion to the west.

7
8 We can gain some perspective on this by considering PATH’s predecessor. An EHV line
9 from Amos to eastern PJM was proposed before any “violations” had been indicated.
10 This was in connection with Project Mountaineer, as discussed above. As suggested by
11 Mr. Pfirrmann, Project Mountaineer’s original goal was to provide access to eastern
12 markets for an additional 5,000MW of western generation. The TrAIL and PATH
13 projects, taken together, are remarkably consistent with such an intent. Some might ask,
14 if PATH is approved, what will be next?

15
16 Q. WHAT IS YOUR VIEW OF THE VOLTAGE STABILITY PROBLEMS CITED
17 BY MR. McGLYNN?

18
19 A. PJM has not proven that the alleged “voltage instability” is a legitimate problem. Mr.
20 McGlynn goes to considerable length to establish voltage instability, but his only
21 evidence – so-called “knee-of-the-curve” analyses – is incomplete. No transient stability
22 results have been shown. “Knee-of-the-curve” analysis is useful as a screening tool, but
23 voltage instability can only be proven by rotor-angle stability analysis in which the

1 dynamic response of the overall system to a sudden disturbance is simulated in the time
2 domain. Neither the applicants nor PJM have presented any such stability results. And
3 all of the cited violations occur at CETO values that I consider to be unnecessarily high.
4 Mr. McGlynn's testimony confirms that there are no voltage issues until transfers into the
5 Mid-Atlantic LDA are well above 6,000MW.

6

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

9

10 A. Whatever voltage problems may exist might be solved by power factor correction.
11 Low voltage problems, whether on an absolute or a voltage drop basis, are generally an
12 indication that reactive (MVAR) loads are too high relative to active (MW) loads. This is
13 reflected by low power factors – i.e. the ratio of MW to MVA. Reactive (MVAR) load is
14 a natural part of power system load, and comes from various apparatus on customers'
15 premises. It can be reduced by the installation of shunt capacitors or static VAR
16 compensators (SVCs), which supply reactive power. Failure to adequately compensate
17 for reactive load means higher MVAR loads as seen from 115kV and 138kV substations,
18 hence lower power factors. Basically, what happens is that the high reactive loads have
19 to be supplied from remote generators and the EHV system, essentially dragging MVARs
20 through all the impedances of the various transmission lines and transformers. This
21 results in larger voltage drops. [A close approximation of voltage drop can be
22 determined by multiplying the per-unit inductive reactance of a line or transformer times
23 the per-unit MVAR flow through it.] Further, the higher power flows through all the

1 lines and transformers will result in higher reactive (MVAR) I^2X losses, and the
2 consequent need to pull even more reactive power off the EHV system, which leads to
3 larger voltage drops, etc. This phenomenon will only get worse as load grows. The best
4 place to correct power factor is to place shunt capacitors on the subtransmission and
5 distribution system – as close to the load as possible.

6
7 Many of the Mid-Atlantic buses listed in PATH's response to SierraVA-IV-51 have
8 power factors below 95% – despite the fact that PJM Manual 14B, Appendix D: "PJM
9 Reliability Planning Criteria" calls for a minimum power factors of 97%.

10
11 Power factor correction is in essence a reduction in reactive (MVAR) load, generally by
12 adding shunt capacitors on the distribution and/or subtransmission systems. If this is
13 impractical for some reason, shunt capacitors can be added at 115 and 138kV substation.
14 If for any reason even *that* is impractical, the applicants themselves have suggested the
15 solution – shunt capacitor or SVC additions at higher voltage stations.

16
17 Power factor correction (reactive compensation) is an ongoing process – it has to be
18 continued year after year as system load grows. It's part of the continuing obligation of
19 providing good utility service. The applicants do not seem to have examined if the
20 voltage problems could be fixed by improving power factors. Nor have they examined
21 the possibility of adding switchable shunt capacitors to some of the 115/138kV
22 substations. We have been told that a "high level" investigation was made which
23 considered adding shunt capacitors at 500kV and 230kV substations without PATH, and

1 this was deemed to be too expensive. But applicants' witnesses in other states have
2 testified that more than 1700MVAR of shunt capacitance will be required at both
3 terminals of the proposed PATH line! (See Dr. Hyde Merrill's testimony.) In any case,
4 no description of the nature of this "high level" investigation was provided. Without a
5 presentation of the results of power factor and lower voltage substation studies, and an
6 explanation of the reactive additions needed by PATH itself, the alleged voltage
7 problems cannot be proven.

8
9 Q. PLEASE DESCRIBE SOME OF YOUR OVERALL IMPRESSIONS OF THIS
10 CASE.

11
12 A. PJM and the applicants demonstrate a distinctly "one track mind" in their planning.
13 Alternatives involving means other than an AC EHV transmission line have not been
14 explored – this is true despite the fact that the problems discovered in the 2009 analyses
15 depict dramatically different limiting facilities than those uncovered in 2008. In fact, the
16 2009 "re-tool" cases came up with a very different set of problems, were less severe, and
17 occurred further out in the future. To most planning engineers, this would suggest that
18 other possible solutions should be examined, but no such attempt has been made. This is
19 especially true if the conclusions are the result of extrapolation. The original PATH
20 proposal remains unchanged, and alternatives remain unexamined.

21
22 There's a built-in bias against any other approach; e.g. the way representation of new
23 generators is handled strongly discourages serious consideration of non-transmission

1 alternatives. Even in the area of transmission itself, no alternatives other than 500 and
2 765kV AC have been examined. A strong case can be made that no additional
3 transmission is needed. But even if additional transmission *is* needed, why hasn't PJM
4 considered building PATH as, for example, an HVDC line? Or why hasn't the
5 conversion of an existing AC line (such as the Mt. Storm-Doubs 500kV line, as suggested
6 by Mr. Merrill) been considered?

7
8 As pointed out by my colleague, Dr. Hyde Merrill, all conclusions beyond the study year
9 of 2014 were based on extrapolation from 2014 results. It's almost inconceivable to me
10 that the need for a major transmission facility, costing in the neighborhood of \$2 billion,
11 would be based on extrapolated results. Extrapolation is also inconsistent with NERC's
12 requirements for long-term studies. As I indicated earlier, the purpose of long-term
13 studies is to provide some indication of the nature and direction of future reliability
14 problems, and to ensure that any recommended short-term solutions will be consistent
15 with future needs. Extrapolation does not, in my view, satisfy that requirement.

16 AEP and its partners seem to have refused to "think outside the box." Perhaps PATH's
17 emphasis on AC EHV transmission, and the effective subsidization of western
18 generation, reflects the potential profits that could be made from transmission usage
19 charges, as well as AEP's ownership of major significant western generating resources.

20 A major facility like the PATH line should not be approved based on extrapolation.

21
22 To summarize:

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

4
5 • PATH would discriminate against eastern generation and other potential resources, and
6 promote western generation, by providing the latter with free access to eastern load
7 centers – all at the expense of the rate-payers.

8
9 • Whereas the rest of the industry utilizes a loss of load expectation of one day in 10
10 years, PJM uses one day in 25 years to determine the import capability required by each
11 Load Deliverability Area (LDA) – which can be quite large. The Mid-Atlantic LDA, for
12 example, has a peak load in excess of 60,000MW. This makes it equal in size to the
13 combined neighboring New York and New England ISOs. Assumptions more in line
14 with the industry, rationalized to a reliability standard equivalent to that used by New
15 York and New England, would result in a CETO which would be lower than the point at
16 which the first reliability violations occur. In other words, there would be no NERC
17 violations.

18
19 • Without this overly conservative approach, CETO values would be lower and there
20 would be no NERC violations. Hence there is no demonstrated need for PATH.

21
22 • Reasonable alternatives, both non-transmission and even transmission, were not
23 considered despite their potential advantages in terms of cost, reliability, and

1 environmental impact. The applicants did not consider any reasonable alternatives based
2 on the currently identified (April 2009) issues.

3

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

8

9 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

10

11 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.

.....

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 (EPAAct) 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 EPAAct, 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 EPAAct, 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 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.

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 of 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. The mere fact of adding transmission does not of itself increase 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. 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 EPAAct 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, EPAAct 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*.

- ☐ Not-Public Document – Not For Public Disclosure
- ☐ 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 update	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

	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

Preparer: Max McFee

Title: Sr, Transmission Product Modeling

Department: Integrated Transmission Planning

Telephone: 612-330-6417

Date: April 7, 2025