UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North Dakota Public Service Commission **Montana Public Service Commission** **Arkansas Public Service Commission** **Mississippi Public Service Commission** **Louisiana Public Service Commission** **Complainants** **v** **Midcontinent Independent System Operator, Inc.** **Respondent**	**Docket No. EL25-109-000**

PREPARED DIRECT TESTIMONY OF JOHANNES P. PFEIFENBERGER AND JOHN MICHAEL HAGERTY

ON BEHALF OF
MIDCONTINENT INDEPENDENT SYTEM OPERATOR, INC.

September 9, 2025

Exhibit MISO-002

Table of Contents

I. Introduction 1

II. Purpose and Summary of Testimony 3

III. Background on Planned LRTP Tranche 2.1 Projects and the Benefit Metrics Used to Assess the Portfolio's B–C Ratio and Reasonableness of Cost Allocations 11

IV. Dr. Hogan's Testimony Misrepresents How MISO Identified and Sited Generation Needed to Meet Projected Load Growth 20

V. Dr. Hogan's Conclusion that the Avoided Capacity Cost benefit of the LRTP Tranche 2.1 Projects Should Be Zero is Unreasonable 32

VI. Dr. Hogan's Conclusion that the "Mitigation of Reliability Issues" Benefit of MISO's LRTP Tranche 2.1 Projects Should be Zero is Unreasonable 46

VII. Dr. Hogan Does Not Attempt to "Correct" for the Fact that Several of MISO's Benefit Metrics Must be Expected to Understate Benefits 51

VIII. Dr. Hogan's Recommendation and the Complaint's Overall Conclusion that the Approval of Tranche 2.1 Projects Should be Reversed Because These Projects Are Not Needed is Inconsistent with Other Studies 58

IX. Regulatory Policy Implications 63

Attachment A: Qualifications of Johannes P. Pfeifenberger A-1

Attachment B: Qualifications of John Michael Hagerty B-1

I. INTRODUCTION

Q: Please state your full names, titles, and business addresses.

A: Our names are Johannes P. Pfeifenberger and John Michael Hagerty. Johannes Pfeifenberger is a Principal at The Brattle Group and based in the company's Boston office. His business address is One Beacon Street, Suite 2600, Boston MA 02108. John Michael Hagerty is a Principal at The Brattle Group and based in the company's Washington DC office. His business address is 1800 M Street NW, Suite 700 North, Washington, DC 20036.

Q: Mr. Pfeifenberger, please summarize your qualifications.

A: I am an economist with a background in power engineering and over twenty-five years of work experience in the areas of regulated industries, energy policy, and finance. I received a M.A. in Economics and Finance from Brandeis University and a M.S. in Electrical Engineering with a specialization in Power Engineering and Energy Economics from the University of Technology, Vienna, Austria. I am the author and co-author of numerous articles, reports, and presentations on subject areas related to wholesale power market design, the economic benefits of transmission investment, transmission planning, and cost allocation, and have advised multiple independent system operators ("ISOs") and regional transmission organizations ("RTOs"), transmission owners, and policymakers on these subject matters. My experience also includes supporting RTOs on tariff designs and seams, reviewing intertie operations and planning, and assessing resource adequacy. I have testified before and filed reports, affidavits, and comments with the Federal Energy Regulatory Commission ("FERC" or "Commission") on a range of subject areas, including

transmission matters. Mr. Hagerty and I have co-authored (with others) a number of reports on transmission benefit-cost analyses, some of which were cited extensively in the Commission's Order 1920. I have also previously testified on behalf of the Midcontinent Independent System Operator Inc. ("MISO") in Docket ER-22-995-001 on the reasonableness of subregional cost allocation for the Multi-Value Projects ("MVP") planned through MISO's Long Range Transmission Planning ("LRTP") processes. My CV with a more detailed description of my qualifications is provided in Attachment A to this testimony.

Q: Mr. Hagerty, please summarize your qualifications.

A: I have an M.S. in Technology and Policy from the Massachusetts Institute of Technology and a B.S. in Chemical Engineering from the University of Notre Dame. I have 12 years of experience in utility and electric power industry planning and regulatory analysis, including: transmission planning; resource planning; valuation of generation, storage, and transmission assets; wholesale market design; and economy-wide deep decarbonization. I have supported transmission developers, generation developers, utilities, state regulators and agencies, and RTOs with transmission planning processes and benefits analyses in MISO and throughout the country. I have submitted reports or testimonies on the transmission planning processes and economic benefits of transmission projects to the Commission, the Wisconsin Public Service Commission (concerning an LRTP Tranche 1 project), the North Carolina Utilities Commission, the Public Service Commission of South Carolina, the New York Public Service Commission, and the California Public Utility Commission. I also submitted independent market reports to the U.S. Department of Energy on the value of transmission projects.

As noted above, we have co-authored (with others) a number of reports on transmission benefit-cost analyses and planning processes, some of which were cited extensively in the Commission's Order No. 1920. My CV with a more detailed description of my qualifications is provided in Attachment B to this testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: We were asked by MISO to respond to the testimony of Professor William Hogan ("Hogan Testimony") concerning the cost-benefit analysis that MISO conducted, and its Board of Directors ("Board") relied upon, to justify approval of a group of transmission projects (the "Tranche 2.1" projects) as Multi-Value Projects in MISO's 2024 Transmission Expansion Plan ("MTEP").

Q: Please summarize the points Dr. Hogan makes in his testimony to which you are responding.

A: Dr. Hogan concludes that MISO's assumptions and cost-benefit analysis contain significant defects that result in MISO overstating the benefits estimates for the Tranche 2.1 projects. Based on his "corrections" of MISO's benefits estimates, he concludes that the costs of MISO's Tranche 2.1 projects exceed their benefits, which he believes would disqualify these projects as Multi-Value Projects ("MVPs") and from using MISO's Commission-approved cost allocation for MVPs.[1]

[1] Testimony of William Hogan filed on behalf of the Concerned Commission at 2 ("Hogan Testimony").

Q: Please summarize your response to Dr. Hogan's testimony and analyses.

A: Dr. Hogan's conclusions and recommendations related to the MISO benefits estimates are unreasonable and inaccurate. This is because he uses ill-supported "corrections" to MISO's benefit metrics while not recognizing understated benefit estimates for other metrics, and a misunderstanding of how MISO determined where future generation resources may interconnect to the grid. The urgent need for significant transmission expansion in MISO, such as offered by the approved Tranche 2.1 projects, has been extensively studied through MISO's stakeholder-vetted LRTP process and has consistently been identified in a number of other national and regional transmission studies.

The "corrections" of Tranche 2.1 transmission benefits offered by Dr. Hogan are unreasonable because:

(1) Dr. Hogan zeroes out two MISO-quantified benefits estimates because he disagrees with certain aspects of how MISO calculated the benefits. The low end of the range that MISO estimates for these two benefits—a 20-year present value of $16.3 billion of "avoided capacity costs" and $14.8 billion of "mitigation of reliability issues" benefits—exceed the $28.6 billion 20-year present value of the projects' costs on their own.[2] Even if one disagrees with specifics of MISO's approach to the benefit calculations, it is unreasonable to simply zero out these benefits. As we show, alternative approaches for calculating the two benefits (that Dr. Hogan simply removes from the analysis) would yield large non-zero values and overall benefits of the Tranche 2.1 projects that exceed project costs.

[2] The investment cost of the Tranche 2.1 projects was estimated at $21.8 billion, yielding a $28.6 billion (2024 dollars) 20-year present value of annual transmission revenue requirements, which includes transmission operating and maintenance costs, taxes, and return on investment in addition to the recovery of the investments.

(2) MISO has shown through detailed probabilistic resource-adequacy simulations that the diversity benefit of expanding regional transmission capacity in the MISO Midwest footprint will reduce its planning reserve margin and avoid significant costs of new generating capacity to meet its resource adequacy requirements. Dr. Hogan incorrectly attributes the value of transmission to MISO's placement of model-built generation capacity in its simulations for justifying a zero value for avoided capacity costs. He does not address the fundamental underlying geographic diversity value that transmission creates by increasing transfer capability between MISO zones, which reduces the overall amount of generation capacity MISO needs to maintain resource adequacy. Transmission that enables such geographic diversification offers an "avoided capacity cost" benefit that clearly cannot be zero as suggested by Dr. Hogan. Numerous industry studies have demonstrated significant resource adequacy and resilience benefits of expanding transmission in a large geographic region. Even if simplistically valued at the cost of building peaking plants, this alternative value of the reduced resource adequacy requirement confirms the magnitude of MISO's estimate.

(3) The multi-value nature of Tranche 2.1 projects clearly offers reliability benefits by helping address MISO's future transmission reliability needs. While Dr. Hogan disagrees with MISO's approach to estimating these reliability benefits, it is clear that in the absence of Tranche 2.1 projects MISO would need to make significant reliability-driven transmission upgrades or take other costly measures to support the high projected load growth and integrate the resources necessary to support that load growth. Dr. Hogan himself notes that MISO would take actions to avoid future

reliability events but does not acknowledge that those actions would also require significant investment in the transmission system and other costly measures to ensure reliability. The proposed Tranche 2.1 projects avoid such incremental "reliability-only" projects that would be necessary to address these future transmission reliability needs. MISO's reliability benefit metric does not directly estimate avoided reliability transmission project costs, but it is equivalent to a finding that, absent the Tranche 2.1 projects, MISO would need to spend at least half of the Tranche 2.1 project costs on such individual reliability projects. This magnitude of savings from MISO having to mitigate future reliability issues is reasonable.

While Dr. Hogan has selectively zeroed out large transmission-related benefits that cannot reasonably be valued at zero, he has neither recognized nor attempted to correct for the fact that several of MISO's quantified benefit metrics will understate actual benefits of the Tranche 2.1 projects. These understated metrics include the fuel and congestion cost savings, extreme weather benefits, and transmission outage cost savings:

(1) Congestion cost savings are understated because the MISO's nodal production cost simulations are based on normalized day-ahead system conditions and perfect foresight, which does not capture the many challenging and often unpredictable system conditions that MISO will encounter in future day-ahead and real-time markets. Transmission upgrades like the Tranche 2.1 projects tend to provide the most value during these types of system conditions. Based on our own studies and analyses by national labs and the New York Independent System Operator ("NYISO") market monitor, MISO's modeling may understate congestion and fuel cost savings by up to 50%.

(2) MISO's extreme weather benefits will be understated because the MISO metric considers only the value of avoiding load shed events during extreme weather events. It does not quantify the very high system costs for serving the load served during extreme weather periods, including during the many hours without load shed events, that can be reduced with additional transmission capacity.

(3) MISO's transmission outage benefits, which are estimated to add less than 1% of congestion and fuel cost savings, appear significantly understated compared to our own prior findings that about 20% of market congestion may relate to transmission outages and Southwest Power Pool's ("SPP") prior analysis finding that transmission outages increase production cost savings by approximately 11%.

Part of Dr. Hogan's critique of MISO's benefits analyses relates to how MISO has placed the new generation needed to serve load. Dr. Hogan's critique is based on the view that MISO did not co-optimize the location of generation additions with transmission through its simulations, implying that the need for Tranche 2.1 projects is driven by MISO placing too much generation far from loads and that the Tranche 2.1 project could be avoided simply by placing generation closer to load. This hypothesis is not consistent with the approach MISO has actually used in developing its long-term generation assumptions. MISO's approach is reasonable and possibly superior to a model-based locational placement by: (1) using the actual locations of planned resources and generator interconnection requests; and (2) siting necessary additional resource based on a careful and stakeholder-vetted process that relies on available market data and detailed siting studies that considered the tradeoff of transmission and generation costs.

More specifically, the locations of new generation needed beyond the planned resources identified by MISO member utilities (i.e., the additional "model-built" resources) were selected based on: (a) the locations of active generator interconnection requests; (b) a detailed study of wind, solar, and storage siting in MISO by Vibrant Clean Energy that analyzed key factors driving siting and optimized the tradeoffs between local and distant generation resources; (c) available grid capacity and grid locations enabled by the previously-approved LRTP Tranche 1 transmission projects; (d) a preference for available brownfield sites (including the sites of retiring plants); (e) the requirement that each of MISO's Local Resource Zones ("LRZs") meeting its Local Clearing Requirement ("LCR") and Planning Reserve Margin Requirement ("PRMR") prior to adding transmission; and (f) additional stakeholder input on MISO's initial generation placement, which moved a number of resources to locations that stakeholders, including the North Dakota Public Service Commission, found to be more realistic.

This resulted in much of the additional generation being placed in locations similar to those of the existing and already-planned generation, creating a mix of local resources and more distant resources. This general mix of local and more distant resources has been found to result in lowest-cost outcomes in prior MISO studies, such as the Regional Generation Outlet Study ("RGOS"), which was the motivation to create the MVP framework that MISO has been using for long-term transmission planning.

In addition, the generation siting analysis occurred independent of the transmission planning studies and so does not represent an approach based on different generation scenarios with and without Tranche 2.1 projects, but instead provides a well-justified outlook for where future generating resources would likely be placed based on the best

available information. MISO's approach to siting new generation resources for long-term transmission planning studies aligns with similar regional transmission planning approaches completed by SPP, the California Independent System Operator ("CAISO"), and the Electric Reliability Council of Texas ("ERCOT").

Dr. Hogan's conclusion that the Tranche 2.1 projects are not needed is inconsistent with the transmission upgrades that would, without a doubt, be needed to serve large increases in projected load—as illustrated by the significant transmission upgrades recently identified by PJM, ERCOT, and SPP— and several national studies documenting the need for and cost-effectiveness of expanding MISO's regional transmission capabilities.

Based on the above, we find that Dr. Hogan's overall conclusion that MISO's Tranche 2.1 projects do not offer sufficient benefits to justify the costs of the projects is unreasonable and his recommendation to revoke their approval by the MISO Board should be rejected.

Q: What would the acceptance of Dr. Hogan's analysis and the five states' complaint mean from a regulatory policy perspective?

A: Accepting Dr. Hogan's recommendation would be highly problematic from a regulatory policy perspective as it would allow two states representing 2% of Tranche 2.1 cost allocations and three states that are not allocated any costs of the Tranche 2.1 projects to cancel the development of grid investments needed to address surging new load growth and interconnect the necessary generating resources in a more timely and cost-effective manner.[3]

[3] Prepared Direct Testimony of Jeremiah Doner at 63.

The need for these transmission investments is also illustrated by recent market outcomes. The 2024 State of the Market Report shows that there was about $1.8 billion of congestion in the MISO real-time energy market in 2023 and 2024 due to insufficient transmission capacity, resulting in significant differences in regional prices.[4] Without regional, backbone transmission upgrades like the Tranche 2.1 projects, congestion in MISO will only increase over time as the system faces larger load growth and ongoing changes to its resource mix. At the same time, generation continues to be delayed in entering the market due to the lack of transmission capacity, creating multi-year delays in the generation interconnection process and limiting cost-effective new entry into the market. Resources that submitted interconnection requests in 2021 have still not completed the necessary interconnection studies.

Rejecting the holistically planned, carefully studied, and already-approved Tranche 2.1 projects would imprudently delay urgently needed transmission infrastructure investments by several years, impede economic growth in MISO's Midwestern subregion, and require many more incremental reliability upgrades, planned in a more piecemeal and reactive fashion, that would likely lead to higher costs in the long term and delays in serving load growth and interconnecting necessary resources across MISO.

Q: Does your testimony imply that the MISO benefit metrics and long-term planning framework Dr. Hogan criticizes cannot or should not be improved?

A: No, not at all. We recognize that MISO's benefit metrics and long-term planning framework can be improved, a fact that MISO acknowledges and has committed to continuing to evaluate opportunities to enhance its LRTP process. However, these

[4] Potomac Economics, 2024 State of the Market Report for the MISO Electricity Markets, June 2025, p. viii.

improvements should be implemented on a going-forward basis—similarly to how MISO and other regional planners have already been using the experience gained from one planning cycle (or gained by others) to refine and improve the approaches used in the next transmission planning cycle.

III. BACKGROUND ON PLANNED LRTP TRANCHE 2.1 PROJECTS AND THE BENEFIT METRICS USED TO ASSESS THE PORTFOLIO'S B–C RATIO AND REASONABLENESS OF COST ALLOCATIONS

Q: Please describe the objective of the MISO LRTP Tranche 2.1 planning process.

A: MISO's LRTP is a process to develop regional transmission projects needed to serve future load growth at least cost with a changing resource mix. As MISO witness Jeremiah Doner explains in detail, the process occurs in multiple phases, or "tranches," to address evolving reliability needs. Tranche 1, approved in July 2022, prioritized foundational upgrades in the Midwest region. Tranche 2.1 projects, approved in December 2024, created an additional portfolio of projects designed to create a high-voltage network across the region.

Q: What future scenarios did MISO model for identifying long-term transmission needs and evaluating the benefits of the Tranche 2.1 projects?

A: MISO primarily relied on Future 2A for the Tranche 2.1 needs assessment and benefits analysis and included Tranche 1 transmission projects in its base case. MISO developed these future scenarios prior to the start of the Tranche 2.1 planning process while updating the Series 1 futures to account for the latest load growth and generation resource assumptions. In the updated Series 1A, MISO developed three futures (Futures 1A, 2A, and 3A). Future 2A represents a higher load-growth relative to Future 1A and assumes that all announced MISO state and member policy goals are met. Future 2A includes roughly

270 GW of total resource additions consisting of a mix of resource types with wind and solar representing a significant share of the additions. Future 3A represents an even higher load growth scenario as well as a further acceleration of generation additions and retirements. However, Future 3A was not a primary driver of the Tranche 2.1 projects. As explained by Mr. Doner, MISO developed the futures with significant stakeholder input, including from utilities and states.

Q: Is Future 2A a reasonable future for identifying transmission system needs and analyzing the benefits of the Tranche 2.1 projects?

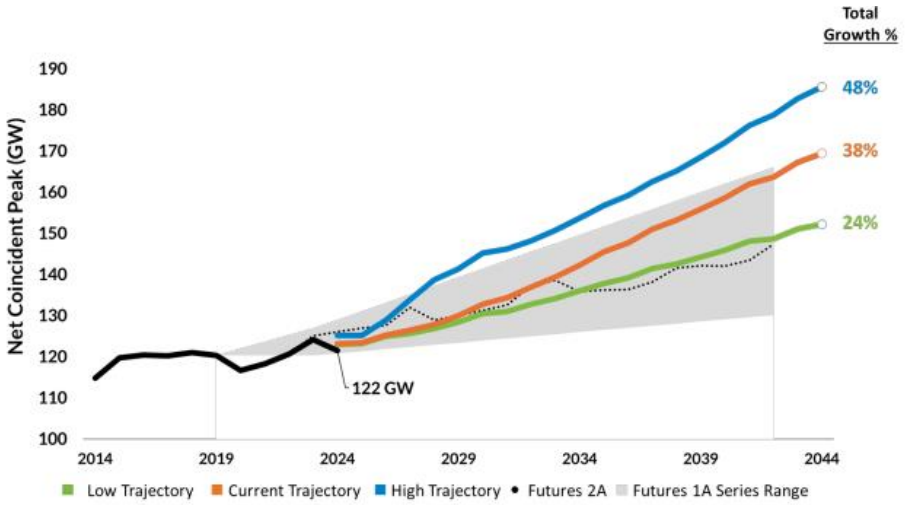
A: Yes, Future 2A is a reasonable future for analyzing benefit-cost analysis, although the MISO load forecast has already increased from the projected Future 2A load.

Q: How well do the Future 2A load growth assumptions align with MISO's most recent projections of load growth?

A: MISO developed Future 2A in 2022 prior to the projection of widespread increase in load due to large load additions, such as data centers. MISO's updated long-term load forecast released in December 2024 demonstrates that MISO load projections have increased considerably relative to the Future 2A projection. As shown in the figure below, Future 2A load growth (the dotted line, in the middle of the updated Futures range as shown by the gray shaded region), now aligns well with the "Current Trajectory" (orange line) through the early 2030s. Starting in 2034, however, the Current Trajectory load forecast is approximately 15 GW higher than Future 2A projection that was used to plan the Tranche 2.1 projects. If the "high trajectory" turns out to reflect MISO load growth, MISO will need to serve approximately 30 GW more than the load growth supported by the Tranche 2.1 projects. This is important since addressing the higher loads starting in 2034

will likely require transmission investments beyond the Board-approved Tranche 2.1 projects.

FIGURE 1: MISO DECEMBER 2024 LONG-TERM LOAD FORECAST

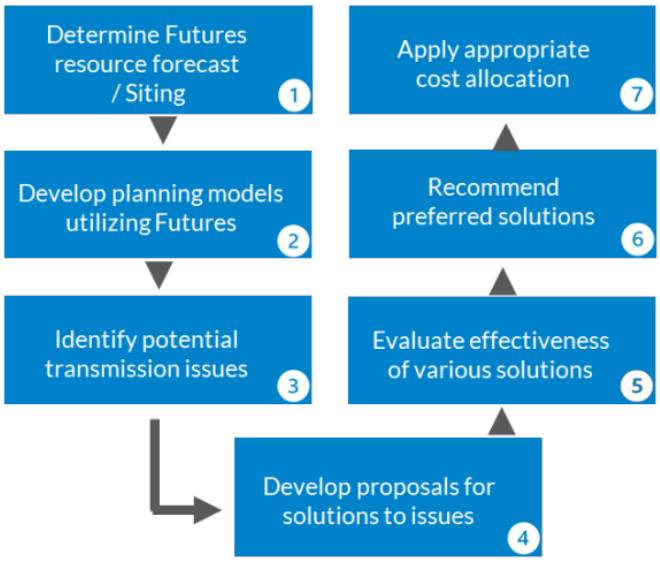


Source: MISO, Long-Term Load Forecast, December 2024, p. 10.

Q: How did MISO use Future 2A to identify future transmission needs?

A: MISO developed the Future 2A scenario prior to beginning the Tranche 2.1 planning process, and it provided the foundation for identifying future generation and transmission needs. Future 2A defined the load growth, resource expansions, resource siting, and electrification assumptions (Step 1 in the figure below) that were directly used in MISO's transmission planning models, identification of transmission needs, and the development and evaluation of transmission solutions (Steps 2–7 in the figure below).

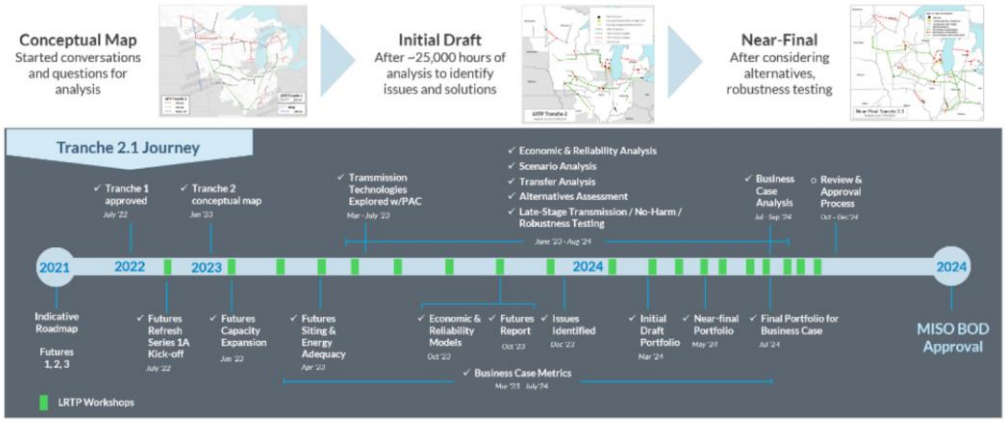
FIGURE 2: LRTP TRANCHE 2.1 7-STEP PROCESS



Source: MISO, MTEP24 Transmission Portfolio, p. 25. ("MTEP24 Full Report")

The timeline of MISO's three-year Tranche 2.1 planning effort from stakeholder approvals of planning futures to MISO's board approval is summarized in Figure 3 below.

FIGURE 3: LRTP TRANCHE 2.1 TIMELINE



Source: MTEP24 Full Report, p. 26

Q: What does the Tranche 2.1 portfolio consist of?

A: The Tranche 2.1 projects are shown in Figure 4 below. The Tranche 2.1 portfolio includes 24 projects and 323 facilities across the MISO Midwest subregion that will add 3,631 miles of 765 kV transmission lines. The estimated total investment cost is $21.8 billion, yielding a $28.6 billion (2024 dollars) 20-year present value of annual transmission revenue

requirements, which includes transmission operating and maintenance costs, taxes, and return on investment in addition to the recovery of the investments.[5]

FIGURE 4: LRTP TRANCHE 2.1 PORTFOLIO



Source: MTEP24 Full Report, p. 161

Q: What is your understanding of the stakeholder process MISO used during the development of these Tranche 2.1 projects?

A: As Mr. Doner explains in more detail, the development of Tranche 2.1 projects included an extensive stakeholder process that resulted in numerous iterations and adjustments leading up to the final scenario and ultimately approval by the MISO Board. The process began with MISO incorporating updated member plans (load growth, announced retirements, goals, etc.) into the futures scenarios. MISO shared preliminary results and collected feedback from stakeholders. MISO compiled this feedback and made adjustments to resource siting among other things. MISO developed a conceptual map of Tranche 2

[5] MTEP24 Full Report, pp. 142, 162.

projects early in the process to allow stakeholders to provide early input on the transmission portfolio. MISO also presented to stakeholders several times on the business case metrics and the preliminary and final results of their benefits analysis. As MISO summarized:

> From Planning Advisory Committee (PAC) meetings that analyze identified issues and proposed solutions, to deep dives in LRTP workshops, and so much more, there have been at least 300 meetings—both internal and external—to arrive at the Tranche 2.1 portfolio. With strong interest in LRTP, workshops averaged 275 participants and multiple other meetings and in-depth discussions were held. Among these various stakeholder meetings, MISO utilized both its public Stakeholder Feedback Tool and its LRTP email to elicit much of the feedback received and inform the inputs, scope and metrics for the Long Range Transmission Panning process. MISO reached out to Stakeholders 10 times across two years for Formal/Informal feedback thru the Feedback Tool; this combined with oral feedback received at LRTP workshops to shape the processes and portfolio.[6]

Q: Which benefit metrics did MISO use for the Tranche 2.1 business case analysis?

A: MISO calculated nine benefit metrics for the Tranche 2.1 portfolio—ultimately grouped into reliability, avoided investment, production cost, and environmental benefits—which

[6] MTEP24 Full Report, p. 26.

resulted in an estimated range of $51.7 to $101.0 billion in total benefits.[7] These metrics include:

- Congestion and fuel savings—reduced costs to run the system through lower congestion and more efficient generation dispatch
- Avoided capacity costs—savings from avoiding the need to build new capacity to meet reliability requirements
- Energy and capacity savings from reduced system losses—additional transmission capacity will reduce system losses, which improves efficiency, lowering the amount of generation capacity and energy needed to serve load
- Avoided transmission investment—savings from reducing or eliminating the need for future transmission upgrades associated with the replacement of aging transmission facilities
- Reduced transmission outage costs—LRTP projects relieve additional congestion attributed to planned and forced outages
- Reduced risk from extreme weather—LTRP projects reduce the risk of unserved energy during periods of weather-related supply shortages
- Decarbonization—emissions reductions attributable to more efficient dispatch of renewables
- Mitigation of reliability issues—LRTP projects reduce thermal/voltage/stability issues which can lead to unserved load

[7] MTEP24 Full Report, p. 142.

These Tranche 2.1 benefit metrics were expanded with stakeholder input from the six metrics used in Tranche 1 (congestion and fuel savings, avoided capacity costs, avoided transmission investment, resource adequacy, risk of load shedding, and decarbonization).[8]

Q: You noted that MISO's benefit metrics changed from Tranche 1 to Tranche 2.1 business case analysis. Is it reasonable to adjust benefit metrics for capturing value of transmission?

A: Yes. The industry is still learning how to best quantify some of these transmission benefits. We would hope and expect that improvements to metrics and analytical tools are made and continue to be made over time. Transmission planners, like MISO, have improved their benefit metrics and analytical tools as a result of gaining experience with prior benefit metrics and quantification, learning from others in the industry, the availability of improved modeling tools, and recognizing that changing transmission needs will require adjustments to benefit metrics to capture the benefits associated with the changing needs. This is also reflected in the fact that the benefit metrics and analytical tools used in the planning of the 2011 MVPs differed from those used for the 2022 Tranche 1 projects, which again differed from those used in the 2024 Tranche 2.1 projects.

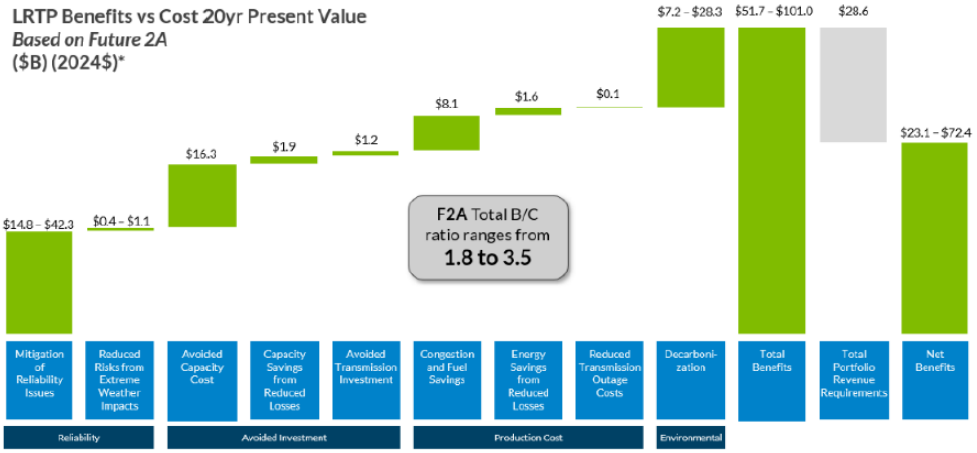
Q: What were the results of MISO Tranche 2.1 business case analysis?

A: As Mr. Doner explains in his testimony, and as shown in Figure 5 below, MISO estimated that the Tranche 2.1 portfolio offset benefits that exceed project costs by a factor of 1.8 to 3.5.

---

[8] The Tranche 1 benefit metric "risk of load shedding" is similar to the Tranche 2.1 benefit metric "reduced risk from extreme weather".

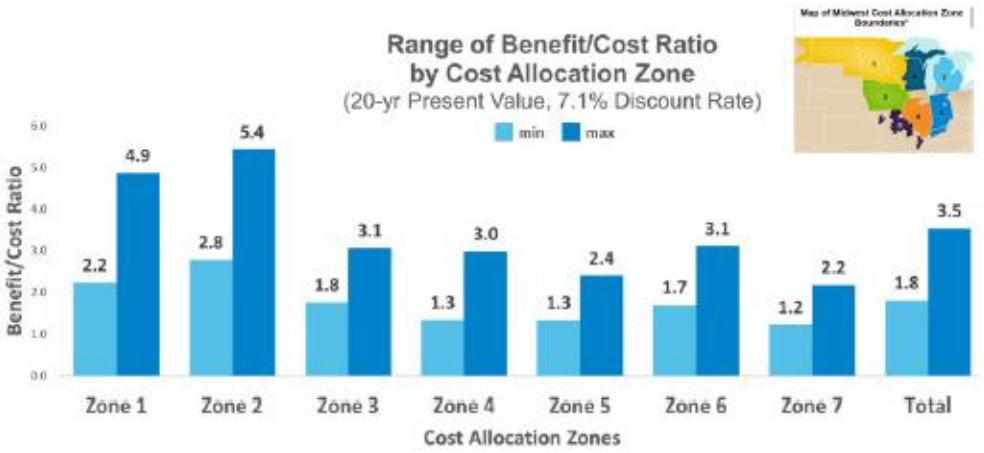
FIGURE 5: TRANCHE 2.1 BENEFIT-COST ANALYSIS RESULTS (SYSTEM-WIDE)



Source: MTEP24 Full Report, p. 142.

MISO also estimated the zonal distribution of benefits relative to the zonal allocation of costs of the Tranche 2.1 projects. As shown in Figure 6 below, the zonal benefit-cost ratios—ranging from a low end of 1.2 to 2.8 to a high end of 2.2 to 5.4—show that costs are allocated roughly commensurate with benefits received.

FIGURE 6: TRANCHE 2.1 BENEFIT-COST ANALYSIS RESULTS (ZONAL)



Source: MTEP24 Full Report, p. 163.

IV. DR. HOGAN'S TESTIMONY MISREPRESENTS HOW MISO IDENTIFIED AND SITED GENERATION NEEDED TO MEET PROJECTED LOAD GROWTH

Q: What does Dr. Hogan claim about MISO's approach to developing necessary planning assumptions for new generation resources in Future 2A?

A: Dr. Hogan claims that MISO's use of a projected generation resource mix and locations based on Future 2A, that are the same for the Base Case and Tranche 2 case, distorts the benefits analysis.[9] Dr. Hogan's critique of MISO's analyses relates to how MISO has placed the new generation needed to serve load, claiming that the need for and benefits of the Tranche 2.1 projects are driven primarily by the generation siting assumptions. Dr. Hogan's critiques MISO for not co-optimizing generation additions with transmission through its simulations, implying that the need for Tranche 2.1 projects is driven by MISO placing too much generation far from loads—and further implying that the Tranche 2.1 projects could be avoided simply by placing generation closer to load.

Q: Are these claims concerning the locations of generation resources accurate?

A: No. Dr. Hogan mischaracterizes and misunderstands how MISO identified and sited future generation facilities to meet the projected load growth and state and utility policies. The claims are not consistent with the actual approach MISO has used in its development of the Future 2A assumptions and planning for Tranche 2.1 projects.

MISO developed the generation assumptions for Future 2A before starting the Tranche 2.1 transmission needs analysis. MISO developed these generation assumptions by projecting the total resources that would be needed across the MISO Midwest Subregion to cost effectively serve the projected load growth, maintain resource adequacy, and achieve

---

[9] Hogan Testimony at 14–15.

state and utility clean-energy goals. This analysis of determining how much generation is needed was undertaken in MISO's capacity expansion model, EGEAS.

Approximately half of the total new generation resources that this analysis found to be required to meet projected future loads over the next 20 years can be met by resources already "planned" by MISO members.[10] The other half of necessary resources is "model-built" resources identified by MISO's capacity expansion analysis. Given the combination of significant load growth and clean-energy goals set by MISO states and utilities, MISO's analysis found that the least-cost generating resources to meet these requirements are a diverse set of wind, solar, battery storage, and natural gas resources.

Developing this type of a long-term outlook for generation is necessary as a starting point for determining long-term transmission needs. In addition to meeting load growth, the consideration state and utility clean energy goals is an essential element to developing these resource projections. In fact, FERC Order No. 1920 specifically requires that long-term regional planning consider such state and utility goals, develop reasonable estimates of the future resources needed to achieve those goals, and include those resources in evaluating long-term transmission needs—just like MISO has done in developing the Future 2A resource mix. Mr. Hogan's critique that MISO's generation assumptions are unreasonable and yield a long-term plan with avoidable generation investments and unnecessary transmission, in part by considering state and utility goals, runs directly against the FERC-mandated long-term planning approach.

Finally, Dr. Hogan in several instances claims that locating generation closer to load would eliminate the need for transmission but provides no evidence to support that serving

[10] MISO, F2A Siting, April 28, 2023.

future load with an alternative future build-out of resources is even possible without substantial transmission investments. Siting this scale of resources and the necessary types of resources to meet state and utility policy goals closer to loads is likely neither possible nor desirable. Siting generation facilities near loads can be challenging and expensive (if it is even possible to build in those locations) due to permitting issues, local opposition, lack of access to fuel, lower quality resources, etc. The locations of utility planned resources in MISO demonstrates that even with significant existing transmission constraints, such a future "locational only" build-out is not being pursued. However, Dr. Hogan simply claims that such a future build-out would eliminate the need for Tranche 2.1 projects and other new transmission capacity without providing any evidence that such a future is possible.

Q: How did MISO determine where the generation additions needed to meet its projected load growth would be located within the MISO footprint?

A: MISO located the planned resources at the sites identified by each of the utilities' resource planners. As Mr. Doner explains in more detail, the additional model-built resources EGEAS identified to be necessary to serve MISO loads were then "sited" across the MISO footprint based on a careful, stakeholder-vetted process.[11] This approach is reasonable and possibly superior to a model-based locational placement. The locations of the model-built generation were selected based on:

(1) the locations of active generator interconnection requests,

[11] MISO, MISO Futures Report: Series 1A, November 1, 2023, pp. 49-51.

(2) a detailed study of wind, solar, and storage siting in MISO by Vibrant Clean Energy that analyzed key factors driving siting and optimized the tradeoffs between local and distant generation resources;

(3) available N-1 grid capacity and grid locations enabled by the previously approved LRTP Tranche 1 transmission projects;

(4) a preference for available brownfield sites (including the sites of retiring plants);

(5) the requirement that each of MISO's LRZs meet its LCR and PRMR prior to adding transmission; and

(6) additional stakeholder input on MISO's initial generation placement, which moved a number of resources to locations stakeholders found to be more realistic.

MISO's approach relies on data sources that implicitly consider the costs of both generation technologies and transmission necessary for interconnecting the resources. Generation developers submit resources into the MISO Generator Interconnection queue seeking out the least-cost locations for building and interconnecting new resources, accounting for both the costs of the generation facilities and the costs of transmission upgrades. Due to the lack of sufficient transmission capacity, the interconnection queue has recently included resources both in locations with the lowest cost generation but likely higher cost transmission and locations with higher cost generation but lower cost transmission. In addition, MISO relied on the Vibrant Clean Energy study that explicitly performs least-cost optimization that considers the tradeoff of generation and transmission costs.[12] Beyond those sources, MISO ensured that each of its zones had enough generation

[12] One of the primary objectives of the study was to "[p]erform detailed modeling of generator, storage and transmission siting using the WIS:dom® optimization tool for the MISO and EIC electricity grids." Vibrant

to meet its zonal resource adequacy requirements, placed generation preferentially at locations with sufficient grid capacity, and utilized available generator interconnection capacity at brownfield sites—all of which will tend to site new resources closer to load. Finally, by providing stakeholders the opportunity to identify shifts in generation locations and then moving a number of resources to different locations based on that feedback, MISO ensured the assumed locations for model-built generation additions are consistent with the needs of its members. For example, MISO moved a significant amount of future wind resources into North Dakota at the request of the North Dakota Public Service Commission.

In addition, it is important to recall the timing of the development of Future 2A and the analysis of the Tranche 2.1 projects. MISO completed the generation resource mix and siting analysis in 2022 and 2023 through a stakeholder-driven process. This was completed prior to the identification of long-term transmission needs associated with projected load growth and generation development and the design of the Tranche 2.1 projects as a solution to the identified long-term needs. In that way, the Future 2A resource mix and locations were not based on a future system with or without Tranche 2.1 projects. Instead, the Future 2A resource mix and locations are a well-justified outlook for where future generating resources would likely be placed based on the best available information at the time.

Given that the projected generation development is needed to meet projected loads, we disagree with Dr. Hogan's claim that "in the absence of the transmission expansion,

---

Clean Energy, Detailed Siting Enhancement of MISO High Penetration Wind, Solar and Storage: Scenario Modeling Results, April 2020.

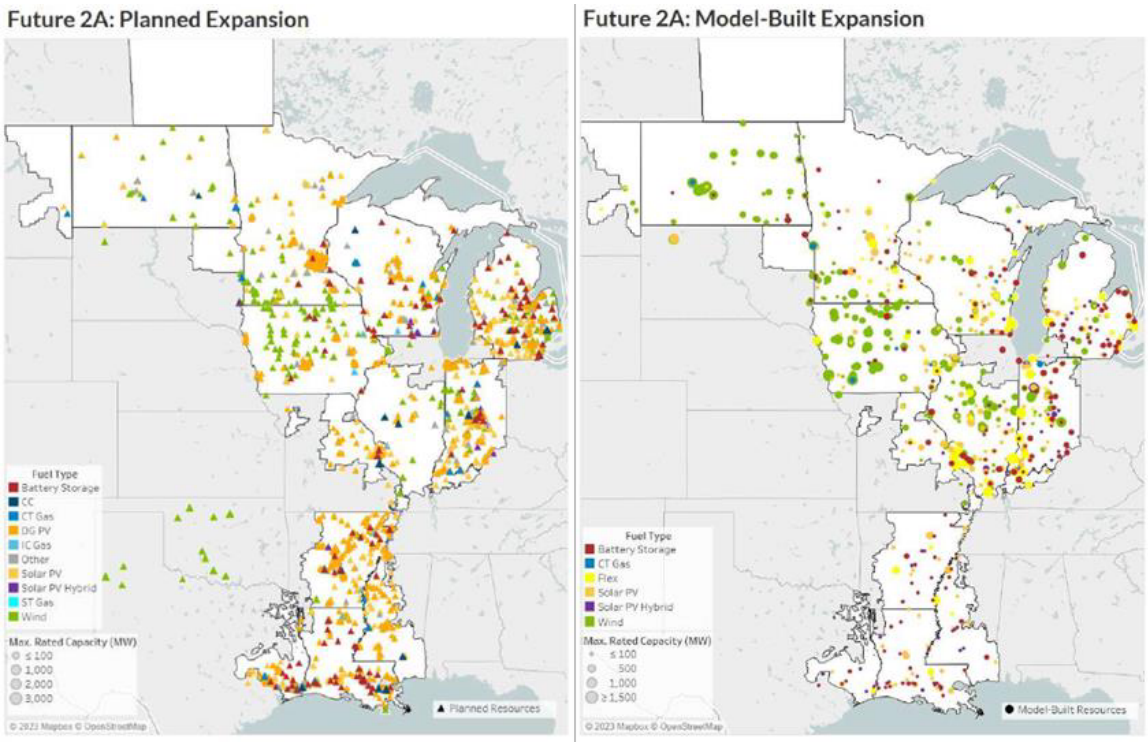
much of this generation would likely not be built."[13] Much new generation clearly is needed to meet projected load growth, yet Dr. Hogan provides no alternative long-term generation outlook, nor offers evidence that alternative generation siting assumptions would actually be superior to the approach used by MISO, which is based on available market data from generation resource planners, MISO generator interconnection requests, available existing transmission capacity, detailed transmission and generation co-optimization studies, and MISO stakeholder input.

Q: Based on MISO's approach, what is the resulting distribution of planned and model-built new resources across the MISO footprint?

A: The distribution of planned and model-built resources for Future 2A are shown in the figures below from MISO's Series 1A Futures report. Both planned and model-built resources are spread across the entire MISO region with the locations of model-built resources very similar to those of the already-planned resources. As shown, new wind, solar and battery storage are added across all zones in MISO Midwest.

[13] Hogan Testimony at 15.

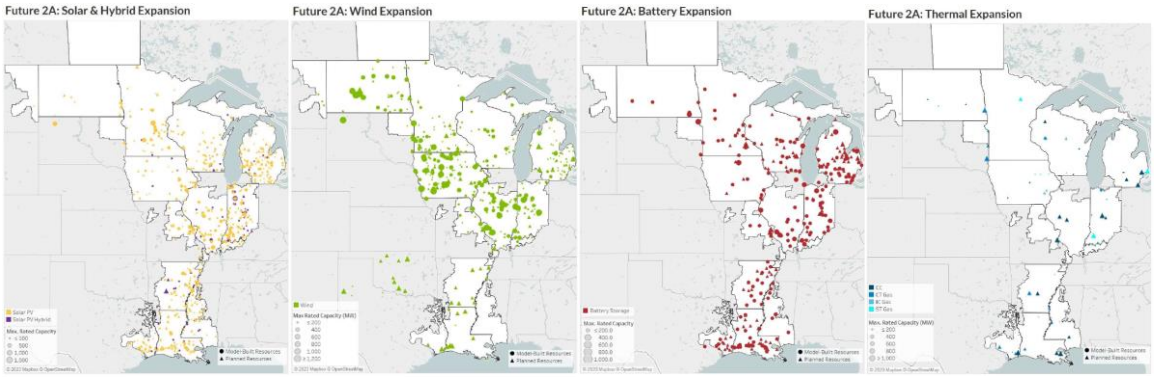
FIGURE 7: MISO FUTURE 2A PLANNED AND MODEL-BUILT RESOURCE ADDITIONS



Source: MISO, MISO Futures Report: Series 1A, November 1, 2023, pp. 84-85.

Looking specifically at the placement of individual resource types, Figure 8 below shows that every resource type is distributed throughout the MISO footprint, resulting in a balanced mix of local and regional resource placements—not one heavily weighted toward low-cost locations that are distant from loads nor toward higher-cost locations closer to load.

FIGURE 8: MISO FUTURE 2A RESOURCE DISTRIBUTION



Source: MISO, MISO Futures Report: Series 1A, November 1, 2023, pp. 78-82.

Of course, the model-built expansion does not align perfectly with the planned expansion due to several factors. For example, most new resources in Michigan are already planned resources, such that MISO did not place as many model-built resources in the state when compared to other states with fewer planned resources.[14] Currently, over 50% of wind resources in the MISO interconnection queue are located in either Illinois or Iowa, resulting in higher density of model-built wind in these states, but MISO also included 14 GW of wind in Wisconsin, Missouri, and Indiana in Future 2A closer to loads in those states. And as noted above, the North Dakota Commission specifically requested that some of the projected future wind generation be assumed to be located in North Dakota, even though less wind generation is currently planned in the state. Solar resources are distributed evenly across the MISO states with no state in the Midwest subregion accounting for more than 20% of the model-built solar additions, while already-planned solar additions are more concentrated in Michigan (41%) and Indiana (25%).

Q: Does this approach result in resources being placed primarily in distant locations so that transmission needs (and associated transmission benefits) are distorted inefficiently as Dr. Hogan claims?

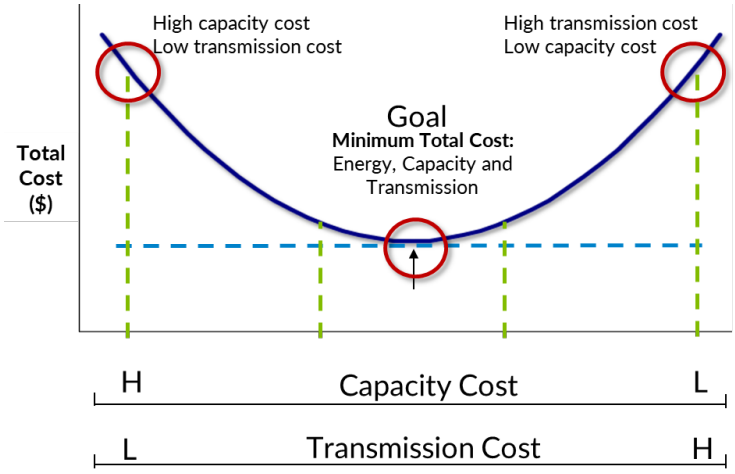
A: No. The figures above show that both the planned resources and model-built resources are spread across the region and model-built resources are not concentrated in distant locations to inefficiently increase the need for transmission. MISO's approach based on available market data, studies and stakeholder input resulted in much of the additional model-built generation being placed in locations similar to those of the existing and already-planned generation, ensuring that each MISO zone has sufficient generation to meet its zonal

[14] Based on detailed siting results posted by MISO for Future 2A: MISO Future Planning Scenarios.

resources adequacy requirements, and creating a mix of local resources and more distant resources.

Prior MISO studies have demonstrated that such a mix of local and more distant resources results in lowest total-cost outcomes. This concept is captured in the "smile curve" chart below (Figure 9) that was originally developed during MISO's Regional Generation Outlet Study ("RGOS") effort and has been used by MISO since then. The figure demonstrates that the lowest cost build-out includes a mix of both local generation and more distant generation in the windiest and sunniest locations. The middle section with the optimal generation and transmission build-out is fairly flat such that slightly more or less local or distant resources do not have a large impact on costs. But costs rise when resources are too heavily concentrated at either end of the spectrum.

FIGURE 9: OPTIMAL GENERATION AND TRANSMISSION BUILD-OUT



Source: MISO, 2019 MTEP, p. 79.

While MISO did not analyze different combinations of generation and transmission for the Tranche 2.1 planning effort, the smile curve concept still applies today. It also is at the center of Dr. Hogan's concern that MISO has placed new generation too far from load centers, which could increase total cost. We do not believe that is the case, though, because

the MISO generation siting assumptions closely align with the locations of already planned resources and are based on the available market data and detailed siting studies for identifying least-cost locations for new resources in MISO.

If anything, one should be concerned that choosing locations that align with member planned resources will tend to place too much generation locally because most MISO utilities now tend to prefer nearby generation for a number of important reasons: (1) less congestion risk; (2) in-state requirements or preferences associated with economic development objectives and clean energy goals; (3) regulatory preferences for nearby resources in the approval of resources choices; and (4) O&M and staffing advantages of more local utility-owned generation.

Q: Is the approach MISO used for identifying the future generation mix and siting those new resources similar to how other regional transmission planners develop future generation assumptions?

A: Yes, this approach of developing a long-term generation resource mix for one or more scenarios that is the same between the base case (without transmission upgrades) and change case (with transmission upgrades) is the most common approach to long-term regional transmission planning across the country. SPP, CAISO, ERCOT all plan their system based on a single future generation portfolio for each scenario modeled.[15] None of these regional planning entities utilize the approach proposed by Dr. Hogan.

---

[15] SPP, 2024 Integrated Transmission Planning Assessment Report, Version 1.0, January 24, 2025; CPUC, Fact Sheet: Decision Transmitting Electric Resource Portfolios to the California Independent System Operator for the 2025-2026 Transmission Planning Process (R.20-05-003), February 26, 2025; ERCOT, 2024 Long-Term System Assessment for the ERCOT Region, December 20, 2024.

In addition, MISO's approach to siting new generation resources for long-term transmission planning studies aligns with similar regional transmission planning approaches completed by SPP, CAISO, and ERCOT. For example, for the placement of new generation needed in its long-term transmission planning efforts, SPP relies primarily on the interconnection queue for siting model-built wind resources and several sources for siting solar, including zonal load, generator interconnection requests, resource quality, transmission capacity, and stakeholder requests.[16] Also similar to MISO, the California Public Utility Commission ("CPUC") creates a single long-term resource mix based on a zonal capacity expansion model, RESOLVE, and then determines nodal resource siting (or "busbar mapping") based on a detailed review of relevant drivers, including the generator interconnection queue, transmission availability, land use considerations, and other factors; the CAISO is then using this CPUC-provided location-specific generation build-out scenario (which is not varied with planned transmission) to identify future transmission needs and develop transmission projects that will solve the identified needs.[17]

Q: Are there any practical challenges to developing separate resource mixes and locations for a base case and change case in a capacity expansion model like EGEAS as proposed by Dr. Hogan?

A: Yes, capturing the details of the transmission system in a capacity expansion model at the level necessary to differentiate between a system without and with a portfolio of transmission upgrades is a significant challenge and may not produce realistic differences in resource mix between the two cases. Even modern capacity expansion models, such as

---

[16] SPP, 2024 Integrated Transmission Planning Assessment Report, Version 1.0, January 24, 2025.

[17] For more information on the CPUC's process for developing the 2025-2025 Transmission Planning Process generation mix, see: CPUC, Assumptions for the 2025-2026 TPP, accessed September 8, 2025.

PLEXOS, that can optimize generation investments over a 20-year or longer timeframe at a zonal level tend to include only a very cursory representation of the physical transmission system. Often these models simulate interzonal transmission capacity as a fixed amount, not able to co-optimize generation expansion with interzonal transmission expansion. Simulation models that allow for such co-optimization will tend to rely on a very simplified representation of transmission expansion costs and transfer capabilities.

Even if one were able to implement these transmission and co-optimization features in a zonal capacity expansion model, MISO would also need to complete extensive research into the very real limits and costs of building different generation types in each zone reflecting differences in permitting requirements, construction costs, resource quality, and other operating conditions to accurately reflect those locationally variable assumptions in the model. Even if done well, this process likely produces different outcomes than the resource plans identified by member utilities and so would require significant efforts to align assumptions and results across many member utilities.

While these refinements are certainly possible and have been undertaken elsewhere to differing degrees, implementing them would require significant efforts by both MISO and its stakeholders and, in the end, may result in resource mixes that are not accepted by stakeholders or yield results very similar to the approach MISO implemented in the Tranche 2.1 LRTP effort.

V. DR. HOGAN'S CONCLUSION THAT THE AVOIDED CAPACITY COST BENEFIT OF THE LRTP TRANCHE 2.1 PROJECTS SHOULD BE ZERO IS UNREASONABLE

Q: One of Dr. Hogan's most consequential "corrections" to MISO's benefit-cost analysis is related to MISO's quantification of avoided capacity costs, which MISO estimated to offer at least $16.3 billion in long-term cost savings.[18] How has he justified eliminating this benefit?

A: Dr. Hogan explains his critique of MISO's avoided capacity cost saving calculation in his discussion of Figure 1 in his testimony.[19] His critique focuses exclusively on the right half of Figure 1 (taken from MISO and copied in below), which shows how MISO used its capacity expansion model, EGEAS, to quantify the capacity that would be needed in MISO's Midwestern footprint to achieve resource adequacy requirements in cases with the geographic diversification and associated resource adequacy benefit offered by the Tranche 2.1 projects (and consequently a lower planning reserve margin) and without Tranche 2.1 projects (and a higher planning reserve margin). Dr. Hogan incorrectly claims that "MISO did not estimate the additional supply that the Tranche 2.1 transmission would provide to each MISO region during high net load conditions with the existing resource mix."[20] We disagree. MISO did in fact use detailed probabilistic simulations to estimate the geographic diversification and resource adequacy benefits of the Tranche 2.1 projects in the "LOLE model" analysis summarized in the left half of his Figure 1.

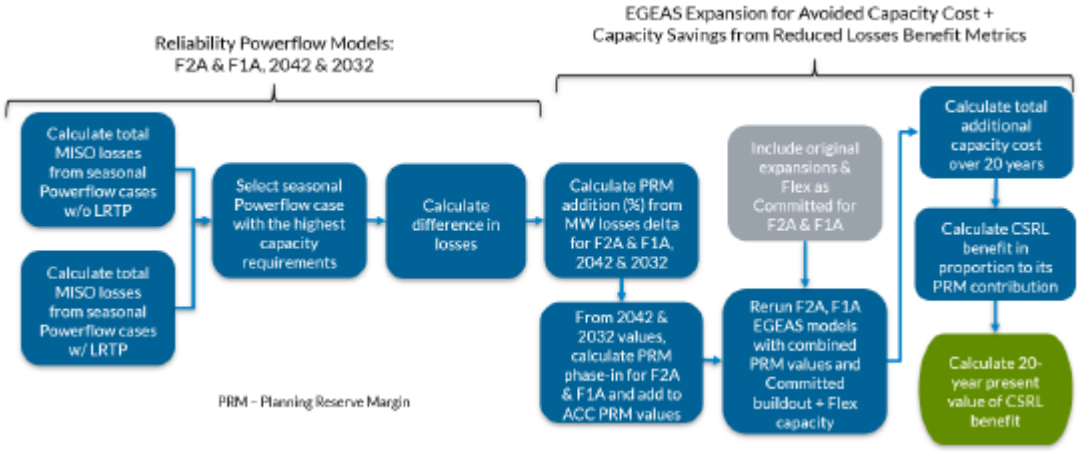
---

[18] Hogan Testimony at 40 (Figure 2). Note that Dr. Hogan also zeroed out the "capacity benefit of reduced losses," which MISO estimated based on the same analyses used for its estimation of avoided capacity costs.

[19] Hogan Testimony at 18

[20] Hogan Testimony at 29.

FIGURE 10: AVOIDED CAPACITY COST APPROACH



Source: MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, p. 13.

The LOLE modeling illustrated in the left half of the figure uses probabilistic simulations to estimate how much higher MISO's planning reserve margin would have to be without that diversity benefit provided by Tranche 2.1 projects. MISO then used an additional EGEAS simulation to estimate the additional generation capacity that would need to be built to meet this higher planning reserve margin. The avoided capacity costs (due to the lower planning reserve margin enabled by the Tranche 2.1 projects' intra-regional transmission expansion) yields the benefit metric MISO has calculated.

Dr. Hogan's testimony does not discuss the fundamental drivers of the Avoided Capacity Cost benefit that MISO evaluates through the LOLE modeling and incorrectly states that "MISO did not analyze [the relevant diversity metric of meeting net load] or even discuss net load and supply variability in the response in the benefits analysis."[21] Instead, he almost exclusively focuses on his disagreements with the additional EGEAS simulations. Dr. Hogan concludes that, without the Tranche 2.1 projects, a significant portion of the needed additional capacity could simply be built closer to load "where it is

[21] Hogan Testimony at 29.

needed and deliverable with the current bulk power system," thus avoiding the Tranche 2.1 projects while also avoiding having to build the more distant generation. He then "corrects" to zero MISO's entire $16.3 billion in estimated avoided capacity cost benefit (plus an additional $1.9 billion in "capacity savings from reduced losses") as shown in his Figure 2.[22]

Q: How do you respond to this aspect of Dr. Hogan's testimony?

A: His focus on MISO's EGEAS modeling misses the very nature of the cost savings MISO attempted to estimate in its Avoided Capacity Cost metric: a more geographically integrated MISO transmission system provides load and resource diversity value that reduces the footprint's resource adequacy requirement and associated planning reserve margin. In other words, if loads and resources can be diversified over a larger geographic footprint by increasing transfer capacity across distant zones, the planning reserve margin needed to ensure resource adequacy can be lowered and less total capacity will need to be built to maintain system reliability, reducing costs to MISO customers. The scale of this transmission-enabled diversity benefit depends on the size and diversity of load as well as the diversity of resources across the footprint. Importantly, the avoided capacity costs are not driven by load growth nor strongly based on assumptions about the location of modeled resource additions, but by the differences in the timing of high demand periods and existing and already planned generation output across the MISO market. Even if load did not grow and no new generation had to be built, increasing the transfer capabilities between MISO zones with different patterns of reliability-driven needs will tend to reduce the total

[22] Hogan Testimony at 40. Dr. Hogan also zeroed out the "capacity benefit of reduced losses" because MISO estimated this benefit based on the same analyses used for its estimation of avoided capacity costs.

planning resource margin requirement and reduce the costs of achieving resource adequacy.

Q: How has MISO approached estimating the impacts of the Tranche 2.1 projects on the planning reserve margin?

A: MISO first estimated how much generation would be needed to reliably serve its projected future load. It then identified the transmission upgrades necessary to serve the projected load from the projected generation. This yielded the Tranche 2.1 projects. For quantifying the avoided capacity costs, MISO then undertook detailed transfer capability studies to determine the capacity import limit ("CIL") and capacity export limit ("CEL") for each of its seven Midwest LRZs with and without the Tranche 2.1 projects. Finally, MISO completed a probabilistic zonal analysis to determine the amount of "firm" capacity and associated planning reserve margin (i.e., the extent to which firm capacity needs to exceed projected peak loads) that is needed to maintain its resource adequacy requirement, which is based on a 1-day-in-10-year (0.1 day/year) LOLE, in a case without the Tranche 2.1 projects and a case with these projects.

Q: How did MISO estimate the extent to which Tranche 2.1 projects increased the capacity transfer limits (CIL/CEL) for its Midwestern reliability zones?

A: MISO has utilized the state-of-the-art, commercially available Transmission Adequacy and Reliability Assessment ("TARA") analysis software to perform CIL/CEL transfer limit studies for the projected 2042 LRTP study year using summer peak, winter peak, and average load reliability power flow models.[23] This analysis found that the Tranche 2.1

[23] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, p. 6.

projects significantly increase the CIL/CEL values of its Midwestern LRZs. For example, in Future 2A, the addition of the Tranche 2.1 projects increases the summer 2042 CIL for LRZ 2 by 4,045 MW.[24]

Q: How did MISO then estimate the reserve margin benefit of the increased capacity transfer limits?

A: MISO used PLEXOS, another well-known and commercially available software tool, to undertake probabilistic analyses to determine how much generation capacity will be needed to meet its 1-in-10 LOLE standard.[25] The LOLE analysis in PLEXOS was undertaken on a multi-zonal basis for MISO Midwest, using probabilistic analysis for 14 weather years of load and renewable generation as well as 150 draws to reflect probabilities of forced outages, including temperature-dependent correlated outages. The analysis accounts for the CIL and CEL values identified by TARA for cases without and with Tranche 2.1 projects and allows resources to be dispatched across the system to serve load. With additional transfer capacity, the same power plant can serve peak load in its zone and another zone in its market if (1) the tightest supply conditions in the load zones occur at different times and (2) there is sufficient transfer capacity to deliver its output to the load in another zone. In its probabilistic LOLE analysis, MISO adjusts either firm generation capacity or the peak load until the 1-in-10-year LOLE standard is met exactly. In a large power system like MISO, loads will peak in different hours and different seasons of the year such that increased transfer capacity reduces the amount of firm capacity needed to maintain resource adequacy.

---

[24] MISO, LRTP Tranche 2.1 Detailed Business Case Analysis Future 2A Final Portfolio, November 6, 2024.

[25] MISO, LRTP Tranche 2 Business Case Metrics Methodology Whitepaper, October 1, 2024, p. 6-8.

Q: What was the result of this LOLE analysis?

A: MISO found that the increased CIL and CEL provided by the Tranche 2.1 projects reduced the amount of firm capacity needed to achieve 1-in-10 LOLE by 13.6 GW, which reduced its planning reserve margin by 8.76% (expressed in installed capacity terms).[26] This result demonstrates that there is significant load and resource diversity across the MISO Midwest market and the addition of the Tranche 2.1 projects will enable load and resource diversity, reducing the total generation capacity costs of achieving maintain resource adequacy.

Q: How did MISO then translate the reduced planning reserve margin enabled by Tranche 2.1 projects into the Avoided Capacity Cost benefit?

A: MISO used its EGEAS model to estimate that 22.8 GW of additional generating capacity of different resource types would be needed by 2042 to meet the higher planning reserve margin without the Tranche 2.1 projects. Phasing in the higher reserve margin in over a ten-year period (between 2032 and 2042) yielded a present value of $16.3 billion in Avoided Capacity Cost savings over a 20-year period.

Q: Which aspect of this analysis does Dr. Hogan disagree with when he "corrects" the avoided capacity cost benefit to zero?

A: Dr. Hogan strongly disagrees with MISO's EGEAS analysis, arguing that building generation closer to load could avoid the Tranche 2.1 projects entirely and, additionally, reduce the total amount of installed capacity by substituting local natural gas generation for distant renewable generation—which is why he "corrects" the $16.3 billion in Avoided Capacity Cost savings to zero.

---

[26] MISO, LRTP Tranche 2.1 Benefits Analysis Results Review, September 25, 2024, p. 10.

Q: Does Dr. Hogan's disagreement with MISO's EGEAS modeling mean that the geographic diversity benefit enabled by the Tranche 2.1 projects' added intraregional transmission capabilities would actually be zero?

A: No. As MISO's detailed CIL/CEL and LOLE analyses show, if the Tranche 2.1 projects were built, they clearly would provide a resource adequacy benefit due to the geographic diversification they enable. Dr. Hogan's hypothesis that the Tranche 2.1 projects could be avoided, and additional generation investments could be eliminated, by placing generation closer to load is unreasonable. His explanation for eliminating the avoided capacity costs is focused solely on where the generation is sited and not on the amount of generation needed. The LOLE analysis demonstrates that the location of the generation is not the source of the Tranche 2.1 projects' resource adequacy benefits. Even if one were to move generation closer to load in one zone, that same capacity may then be limited in meeting peak load in another zone if there is insufficient transfer capacity between the zones, which could then yield an outcome in which more generation needs to be built in the other zone at higher total cost to the ultimate ratepayer.

The substantial projected load growth (which Dr. Hogan does not question) will require substantial generation investment and large alternative transmission upgrades even if the Tranche 2.1 projects were eliminated and generation were placed even closer to load. While placing more generation closer to load, a point we address further below, may somewhat change MISO's LOLE result, it would not eliminate the significant geographic diversity value that the Tranche 2.1 projects offer. More importantly, as discussed in the prior section of our testimony, MISO has already placed much of its generation close to

load—in part to make certain that each MISO zone would meet its zonal resource adequacy requirement even prior to adding the Tranche 2.1 projects.

Q: Can the resource adequacy value of the geographic diversification benefit enabled by the Tranche 2.1 projects be estimated without MISO's EGEAS simulations?

A: Yes. A simplified approach to quantify the Avoided Capacity Cost benefits associated with a lower planning reserve margin can be undertaken as a check on the MISO-estimated cost savings by directly utilizing the reduced firm capacity needs from the LOLE modeling and applying an estimate of the cost of adding capacity, such as the cost of a peaking unit or the net cost of new entry ("net CONE").

To illustrate this value, we requested from MISO the firm capacity reduction due to the addition of the Tranche 2.1 projects from the LOLE modeling. MISO explained that its base case LOLE simulations (with base-case future generation capacity and Tranche 2.1 projects) showed that the increased CIL/CELs due to Tranche 2.1 projects will enable greater geographic diversification and allowed MISO to *reduce* firm capacity by an estimated 9,625 MW relative to the EGEAS results. In the case without the added capacity transfer capability provided by the Tranche 2.1 projects, MISO estimated that it would need to *add* 4,025 MW of firm capacity to meet its LOLE standard due to the inability to take advantage of added geographic diversity. The difference between the two cases is a 13,650 MW reduction in firm capacity needs due to the diversity benefit of the Tranche 2.1 projects.[27] Being able to avoid 13,650 MW of firm capacity needs has not only significant value in terms of avoided capacity costs, but also offers risk mitigation and reliability value

[27] Under MISO's Tranche 2.1 metrics, 90% of the firm capacity reduction would be attributed to resource adequacy benefits of avoided capacity costs while 10% of the firm capacity would be attributed to "capacity savings from reduced losses." Dr. Hogan "corrects" to zero both types of these capacity savings.

considering the challenges associated with emerging rapid load growth, supply chain challenges for new generation, and long interconnection and permitting timelines. MISO's avoided capacity cost estimates are conservative since they do not account for these added risk mitigation and reliability benefits.

Q: Have you used alternative approaches to estimate the generation investment cost savings associated with being able to avoid 13,650 MW of firm capacity due to the resource adequacy value of added geographic diversity offered by the Tranche 2.1 projects?

A: Yes. If an additional 13,650 MW of natural-gas fired combustion turbine plants are needed without Tranche 2.1 projects, assuming an installed cost of $1,700/kW,[28] the avoided construction costs of these peaking plants would yield total investment cost savings of $23 billion. Recognizing that a portion of the total investment cost savings associated with new peaking plants would be offset by energy and ancillary service margins of new resources and savings will not be realized until the 2030s (but investments costs of CTs would be even higher in the future), this alternative approach roughly confirms the magnitude of MISO's avoided capacity cost savings of $16.3 billion.

As another reference point, we calculated the present value of the avoided capacity savings based on MISO's annualized net CONE value of $80/kW-year for its Midwest (North/Central) subregion for Planning Year 2025/2026.[29] Assuming 13,650 MW of avoided resources are phased from 2032 to 2042 (consistent with MISO's planning reserve margin assumption), this net CONE approach yields a present value of roughly $12 billion

---

[28] Based on installed CT capacity cost estimates in Table 13 of Brattle 2025 CONE Report for PJM.

[29] The average net CONE value in MISO Midwest Subregion is $79,777/MW-year. MISO, 20240923 RASC Item 03 CONE and Net CONE Update, Sept 23, 2024, for planning year 2025/26.

of avoided capacity costs (in 2024 dollars, including the capacity savings from reduced losses, which Dr. Hogan also set to zero). While this alternative estimate of cost savings is lower than MISO's $16 billion estimate derived from its more detailed capacity expansion simulations, even this lower value represents sufficient benefits to support the approval of the Tranche 2.1 portfolio.

These two alternative approaches to estimating the avoided capacity costs of Tranche 2.1 projects based on the LOLE study results thus further demonstrate that Dr. Hogan's recommendation to include *zero* avoided capacity cost benefits is unreasonable.

Q: Is the ability of transmission upgrades to enable resource adequacy savings through geographic diversity broadly recognized?

A: Yes. For example, the North American Electric Reliability Corporation ("NERC") recently analyzed this type of diversity benefit in the Final Report of its Interregional Transfer Capability Study ("ITCS"), concluding that 35,000 MW of regional and interregional transmission additions—including 2,000 MW of transmission expansion between the Eastern and Western portions of MISO—would be "prudent" in the near term solely to capture the value of diversifying load and resources over a larger geographic footprint during heat waves, cold snaps, and other weather events.[30]

Similarly, the U.S. Department of Energy's ("DOE") National Transmission Planning Study ("NTPS") found that total transmission capacity would optimally expand by "2.5 to 3.3 times the 2020 system by 2050" and that, by doing so, "approximately $1.60 to $1.80 is

[30] NERC, Interregional Transfer Capability Study (ITCS) Strengthening Reliability Through the Energy Transformation, n.d., Table ES.1.

saved for every dollar spent on transmission."[31] Importantly, one driver of this transmission expansion "is from the increasing value of using interregional transmission for resource adequacy" which "can save the U.S. electricity system hundreds of billions of dollars."[32]

Our 2021 report, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, which the Commission cited extensively in its Order No. 1920, also explained the ability of transmission to reduce planning reserve margins:[33]

> Using transmission to aggregate diverse loads allows peak electricity demand to be met with less generating capacity, as localized peaks in demand can be met using surplus generating capacity from other areas that are not experiencing peak demand at the same time. For example, the June 2021 West Coast heat wave was quantified as a 1-in-1000 year event in the Pacific Northwest, yet grid operators were able to keep the lights on because the heat wave most severely affected California and the Pacific Northwest at different times, allowing each region to meet load using imports from the other region that were only possible because of sufficient transmission interconnection.

In other words, the geographic diversity benefit enabled by transmission expansion allows for the reduction of firm generating capacity (i.e., planning reserve margins)

---

31 DOE, National Transmission Planning Study. Executive Summary, pp. 10-11.

32 DOE, National Transmission Planning Study. Executive Summary, pp. 2, 11.

33 Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, pp. 40-43.

required to maintain resource adequacy standards. Transmission expansion achieves these benefits by enabling the sharing of generation resources and diversification of peak loads and weather-correlated generation (such as renewable energy outputs and thermal generation outages) across larger geographic areas. This diversification reduces system-wide costs and strengthens the grid's ability to meet demand.

Similar diversity benefits of transmission have been quantified in other transmission-related studies, as summarized in our 2021 report. SPP's 2016 Value of Transmission report found its recent transmission investments reduced SPP's planning reserve margin by two percent, yielding savings of $1.34 billion from reduced generating capacity costs. The transmission upgrades also lowered on-peak transmission losses and reduced the need for generating capacity, saving an additional $92 million.[34] In Wisconsin, the Public Service Commission noted that "the addition of new transmission capacity strengthening Wisconsin's interstate connections" was one of three factors that allowed it to reduce the planning reserve margin from 18% to 14.5%.[35]

Recently, Idaho Power agreed to procure a portion of the 500 kV Southwest Intertie Project-North ("SWIP-North") transmission project from Idaho to Nevada to take advantage of load diversity between its system and the Southwest U.S. by procuring excess Southwest winter capacity to meet its winter planning reserve requirement. This case

---

[34] SPP, The Value of Transmission, January 26, 2016, p. 16.

[35] Public Service Commission (PSC) of Wisconsin, *Order*, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, October 9, 2008, p 5. Two other changes that contributed to this decision were the introduction of MISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state

demonstrates how transmission can allow regions to share the same resources to achieve resource adequacy, effectively reducing the combined reserve margin of the two regions.[36]

In short, Dr. Hogan's "correction" of the geographic diversity benefits offered by MISO's Tranche 2.1 projects is unreasonable and inconsistent with industry studies and practice.

Q: Dr. Hogan also criticizes MISO for not including the so-called "Flex Units" in its LOLE simulations.[37] Is this a valid concern that would invalidate the resource adequacy benefit provided by the added capacity transfer limits MISO has estimated through its LOLE simulations?

A: No. First, Dr. Hogan's critique is based on a misunderstanding on how Flex Units were considered in MISO's zonal LOLE simulations. We confirmed with MISO staff that the zonal LOLE simulations did in fact include the Flex Units in both the cases without and with Tranche 2.1 projects.

Second, the inclusion or exclusion of Flex Units in MISO's LOLE simulations would not fundamentally change the estimated resource adequacy benefit and associated avoided capacity cost savings because adding Flex Units does not fundamentally change the nature and magnitude of load and resource diversity across the large MISO footprint. Even without any load growth and generation addition, the increased capacity transfer limits would have provided significant resource adequacy benefits. In fact, as noted above, MISO's LOLE simulations of the case with Tranche 2.1 projects shows that the assumed

---

[36] "Idaho Power's involvement in SWIP-North allows us to import up to 500 megawatts of power from south to north. That's enough for more than 225,000 homes during peak winter use." Idaho Power, SWIP-North, accessed August 29, 2025.

[37] Hogan Testimony at 17.

capacity additions could be reduced by 9,625 MW and still meet its resource adequacy standards. While the "flex units" were added to address flexibility constraints during morning and evening ramping periods in MISO's PROMOD production cost modeling, which may be caused by limitations of EGEAS to account for chronological issues like those identified by MISO, the need for these Flex Units is not driven by MISO's resource adequacy requirement.

Q: Dr. Hogan also criticizes MISO for not having considered in its EGEAS capacity expansion simulations how the addition of different resource types changes the capacity accreditation renewable resources.[38] Does that invalidate the avoided capacity costs?

A: No. The probabilistic LOLE simulations MISO used to estimate the resource adequacy benefits and associated reduced capacity needs with the addition of the Tranche 2.1 projects do not rely on the accredited capacity value of renewable generation. Rather, MISO's probabilistic simulations reflect the hourly wind and solar profiles of 14 historical weather years, which means the actual ability for these resources to avoid reliability events across a range of realistic assumptions (not an assumed fixed ELCC value) is reflected in MISO's LOLE simulations and its estimated resource adequacy requirements and planning reserve margins.

[38] Hogan Testimony at 16.

VI. DR. HOGAN'S CONCLUSION THAT THE "MITIGATION OF RELIABILITY ISSUES" BENEFIT OF MISO'S LRTP TRANCHE 2.1 PROJECTS SHOULD BE ZERO IS UNREASONABLE

Q: Dr. Hogan also "corrects" to zero MISO's "mitigation of reliability issues" benefit metric.[39] How has he justified eliminating this benefit, which MISO estimated to offer at least $14.8 billion in long-term benefits?

A: Dr. Hogan explains his critique of MISO's mitigation of reliability issues metric (to which we refer as "transmission reliability benefit") in his testimony as follows:

> If Tranche 2.1 transmission investments were not made, and the alternative generation built, the alternative generation would of course be sited to meet these reliability needs. Hence, there would be no reliability benefits to the Tranche 2.1 transmission because the reliability issues would be addressed by the generation that would be built if the Tranche 2.1 transmission was not built.[40]
>
> MISO quantifies this reliability benefit based on the cost of load shedding that would be needed to resolve the reliability issues. In MISO's benefits assessment there is a large amount of assumed load shedding. In actual practice, known reliability issues would not be resolved by planning to shed large amounts of load. Instead, these types of reliability issues are identified and addressed in near-term planning processes. The solutions

[39] Hogan Testimony at 40 (Figure 2).

[40] Hogan Testimony at 33.

> could include incremental transmission upgrades, voltage support equipment, or generation investments…[41]

Q: How do you respond to this aspect of Prof. Hogan's testimony?

A: Dr. Hogan's justification for zeroing out the $14.8 billion in estimated transmission reliability benefits of Tranche 2.1 projects is flawed and unreasonable in several aspects.

First, Dr. Hogan seems to assume that transmission reliability needs associated with the substantial MISO load growth could simply be resolved by siting generation differently such that the need for transmission expansion would be avoided. Even if all new generation was sited at or near customer locations, however, substantial local and regional reliability transmission investments would still be necessary to (1) serve the growing load, (2) deliver the local generation to nearby loads, and (3) deliver the generation to other loads whenever local load and generation output do not coincide. There is simply no way to serve the projected load growth and interconnect the required large amounts of new generation without any reliability-driven transmission investments. If not planned now through the LRTP Tranche 2.1 effort, such reliability-driven transmission upgrades would have to be planned on a shorter-term and more piecemeal basis through MISO's local and regional reliability planning processes. Planning the transmission system in this way is likely to result in less-efficient, higher-cost solutions and delays in the interconnection of new loads and generation resources, as recognized by the Commission in its requirement in FERC Order No. 1920 to perform long-term regional transmission planning.

---

[41] Hogan Testimony at 35.

Second, Dr. Hogan's conclusion appears to be based on a misunderstanding of MISO's transmission reliability benefit metric. MISO's transmission reliability metric is not based on the assumption that load would actually be shed in the future. Rather, MISO first projected through detailed power flow analyses the reliability violations that would exist without Tranche 2.1 projects. It then quantified by how much load would need to be reduced to avoid these reliability violations. As Mr. Doner explains, the amount of load reduction is then valued at the Value of Lost Load ("VOLL") as a monetary measure of the reliability risks that MISO would face without the Tranche 2.1 projects. This reliability risk metric allowed MISO to avoid the substantial effort of projecting all reliability-driven transmission upgrades that MISO would need to eventually make over the next 20-40 years in a hypothetical world without the Tranche 2.1 portfolio, identifying near-term reliability upgrades piece-by-piece through annual future local and regional reliability planning effort.

While the MISO reliability risk metric is a novel approach, we believe it is a reasonable proxy for the long-term, real-world transmission reliability benefits provided by MISO's Tranche 2.1 projects: proactively and holistically creating a long-term,multi-value transmission plan will avoid the many incremental reliability projects that would be needed and planned over several future near-term planning studies without Tranche 2.1 projects. In our opinion, MISO's estimated reliability value of addressing identified overloads based on the VOLL serves as a reasonable proxy for the avoided costs for resolving reliability violations through incremental reliability-driven upgrades in a world without the Tranche 2.1 multi-value projects.[42]

---

[42] Note that these avoided cost of future reliability-only upgrades far exceed the "avoided transmission investment" benefit MISO calculated for based only on Tranche 2.1 upgrades to aging existing lines, which avoids future refurbishment costs of the aging lines, but does not address the much broader set of reliability projects MISO would have to plan to serve its quickly growing loads.

Even Dr. Hogan acknowledges in his testimony that MISO's reliability planning processes would ensure that "these types of reliability issues are identified and addressed in near-term planning processes" and that "[t]he solutions could include incremental transmission upgrades."[43] Yet, he attributes zero value to Tranche 2.1 projects avoiding the cost of such alternative solutions, including the value of avoiding "incremental transmission upgrades," that MISO would need to identify through annual near-term planning processes.

In our experience, it is safe to assume that over the next 20-40 years a substantial amount of incremental transmission upgrades would need to be approved through MISO's local and regional reliability planning processes to address the reliability issues created by the substantial projected load growth and the interconnection of generating resources, no matter where these loads and resources will be located in the MISO footprint.

In short, because the Tranche 2.1 projects will avoid the need for many future local and regional reliability-driven transmission investments, the Tranche 2.1 projects provide significant transmission reliability benefits and Dr. Hogan's recommendation to zero out these benefits is unreasonable.

Q: Does MISO's analysis of the value of mitigating reliability issues result in a reasonable estimate of the benefits of Tranche 2.1 projects?

A: Yes, MISO's estimate that these reliability benefits amount to at least $14.8 billion, or approximately half of the $28.6 billion (2024 dollars) in Tranche 2.1 costs, is a reasonable

---

[43] Hogan Testimony at 35. Note that Dr. Hogan also suggests that "operator actions" could be undertaken to solve reliability issues (at 36). While it is true that "operator actions" will address reliability challenges that occur during system operations, they will not generally be a sufficiently effective "solution" to address most of the transmission reliability needs that have to be addressed under NERC transmission planning standards.

if not conservative estimate. MISO's reliability analysis demonstrates a significant portion of the thermal reliability violations on their system in Future 2A are resolved with the addition of the Tranche 2.1 projects. Based on the Thermal Severity Index metric, Tranche 2.1 projects reduce the severity of thermal violations projected for 2032 by 47% during summer peak conditions, 52% during winter peak conditions, and 80% during low load conditions.[44]

Because Tranche 2.1 projects are planned more proactively and more holistically than MISO's more near-term and incremental reliability-driven planning processes projects, it may well be that the cumulative long-term costs of such incremental reliability-driven upgrades would exceed the costs of MISO's Tranche 2.1 projects.

Q: Are there any reference points for the order of magnitude of reliability-driven projects that MISO's Tranche 2.1 projects may avoid?

A: Yes, transmission planning processes in PJM and ERCOT have recently identified significant reliability-driven transmission projects required to support large load increases. In the 2024 Regional Transmission Expansion Plan ("RTEP 2024"), PJM incorporated an updated load forecast that increased the peak load in the 2030s by about 20 GW relative to its prior forecast.[45] The RTEP 2024 planning cycle resulted in $5.9 billion in baseline reliability-driven transmission upgrades to serve these higher load growths.[46] This yields reliability-driven transmission investments of $295 per kW of load growth in PJM. Similarly, ERCOT completed in 2024 a systemwide transmission planning study to identify the reliability upgrades required to support a 150 GW summer peak load in 2030, a 54 GW

---

44 MTEP24 Full Report, p. 82.

45 PJM Interconnection, RTEP 2024, April 17, 2025, p. 19.

46 PJM Interconnection, RTEP 2024, April 17, 2025, p. 1.

increase in summer peak load compared to the 2023 Regional Transmission Plan.[47] The 2024 ERCOT study identified $33 billion in reliability upgrades to support this amount of load growth, or $611/kW.[48]

MISO is projecting in Future 2A an increase in peak load of 21 GW of peak load relative to Future 1 (the basis for Tranche 1).[49] Using the recent reliability-driven studies in PJM and ERCOT as a benchmark, reliability-only upgrades to meet 21 GW of load growth in MISO would range from $6.2 billion to $12.8 billion of reliability-driven transmission investments, or $8.1 billion to $16.8 billion (2024 dollars) of avoided revenue requirements over 20 years.[50] The low end of MISO's analysis of the benefits of mitigating future reliability needs ($14.8 billion) falls squarely within this range, further demonstrating the reasonableness of MISO transmission reliability benefit metric.

VII. DR. HOGAN DOES NOT ATTEMPT TO "CORRECT" FOR THE FACT THAT SEVERAL OF MISO'S BENEFIT METRICS MUST BE EXPECTED TO UNDERSTATE BENEFITS

Q: Dr. Hogan zeros out the MISO transmission benefits metrics that he believes to overstate the actual benefits of Tranche 2.1 projects. Has he considered in his

---

47 ERCOT load forecast: ERCOT, Load Forecast, accessed September 8, 2025;
2024 RTP Report: ERCOT, 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison, January 2025, p. 25;
2023 RTP Report: ERCOT, 2023 Regional Transmission Plan, December 2023, p. 25.

48 ERCOT, 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison, January 2025, p. iii.

49 Future 1 projected peak load is 137 GW in 2040 and Future 2A projected load is 158 GW in 2042.

50 Based on the ratio of MISO's 20-year revenue requirements for Tranche 2.1 of $28.6 billion compared to $21.9 billion of investment costs. MISO, LRTP Tranche 2.1 Detailed Business Case Analysis Future 2A Final Portfolio, November 6, 2024.

testimony if any of MISO's benefit metrics might *understate* actual Tranche 2.1 benefits?

A: No, he has not.

Q: Do you believe any of MISO's Tranche 2.1 benefit metrics understate the projects benefits?

A: Yes. We believe three of MISO's Tranche 2.1 benefit metrics understate the projects' benefits. These include MISO's benefit estimates for (1) $8.1 billion in congestion and fuel savings; (2) $0.39 billion in reduced risks from extreme weather impacts; and (3) $0.076 billion in reduced transmission outage costs.

In addition, MISO's "avoided transmission investment" savings metric only considered the extent to which Tranche 2.1 projects are based on upgrades to aging existing lines, which avoids future refurbishment costs. This avoided transmission investment metric does not include any future local and regional reliability upgrades that will be avoided (beyond aging transmission replacements) by the Tranche 2.1 projects as approximated by MISO's "mitigation of reliability issues" metric and discussed in the prior section of our testimony.

Q: Why do you believe MISO's estimated $8.1 billion in congestion and fuel savings are understated?

A: The congestion and fuel cost savings are understated because the MISO's nodal production cost simulations are based on highly normalized system conditions and perfect foresight. This does not capture the many challenging and often unpredictable system conditions that MISO has been and will be encountering in its future day-ahead and real-time markets.

As researchers from Lawrence Berkeley National Laboratory ("LBNL") have documented, approximately 50% of total regional and interregional transmission value is concentrated in just 5% of all hours in a decade, with 20–30% of total transmission value concentrated in only 1% of all hours.[51] Importantly, a large portion of that transmission value is not reflected in day-ahead markets, and only are realized during real-time market conditions, because "[u]nforeseen intraday variance, high net load, cold weather, or high renewable power generation conditions are present in over 75% of the hours with peak transmission value."[52]

Production cost simulations based on normalized conditions are unlikely to capture the type of market conditions that account for 50% of transmission value but are incurred during only 1%–5% of all hours. The fact that MISO's simulations are also based on perfect foresight further means that the large portion of transmission benefits that are experience only during real-time conditions will not be captured. In fact, the LBNL research shows that the average value of transmission during real-time market operations exceeds the value captured in day-ahead energy markets by about 40%.[53] This is the case even though day-ahead energy markets capture many challenges (beyond those that would be captured by MISO's normalized production cost simulations) since they reflect day-ahead forecasts of challenging market conditions, such as heat waves, cold snaps, fuel price spikes, or unusually-high transmission outages. As we have discussed in our 2021 report,[54]

---

51 Nature Communications, "Electric transmission value and its drivers in United States power markets," August 28, 2025, Figure 5.

52 *Id*, Figure 6.

53 *Id*, Figure 4.

54 Pfeifenberger, Johannes, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, pp. 35-37 and Appendices B and C.

which the Commission cited extensively in its Order 1920, these and other factors lead to significantly understated estimates of transmission benefits in the type of production cost simulations MISO has used to estimate the congestion and fuel cost savings associated with the Tranche 2.1 portfolio.

Q: Are you aware of any studies estimating by how much traditional production cost simulations would understate congestion and fuel cost savings?

A: Yes. For example, Mr. Hagerty is the co-author of a study performed for NYISO and the New York Department of Public Service ("NYDPS") that estimated that 56% of real-world congestion is "missed" by the type of production cost simulation used by MISO in its Tranche 2.1 benefits analysis—justifying a 56% upward adjustment to simulated production cost savings.[55] The NYISO Independent Market Monitor has similarly recommended a 40% upward adjustment to simulated production cost savings in recognition that production cost simulations do "not fully capture the value of new transmission lines" including due to "transmission outages" and "unforeseen factors such as load forecast error that exacerbate congestion during actual market operations." [56]

Q: Why do you believe MISO's "low" estimate of $0.39 billion in reduced risks from extreme weather impacts is understated?

A: MISO's extreme whether benefits will be understated because the MISO metric considers only the value of avoiding load shed events during extreme weather events. This benefit of avoided load shed events does not quantify the very high system costs associated with

---

[55] Newell, Samuel, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015, pp. 86 and 89.

[56] Patton, David, et al., NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects, June 2018, p. 15.

serving load during extreme weather periods such as cold snaps, heat waves, and renewable droughts, most of which are not associated with load shed events. In other words, MISO's metric does not account for (1) the high cost of serving its remaining load during load shed events (which occur less far frequently than extreme weather conditions and rarely shed more than a few percentage of actual load) and (2) the high cost of serving load during the more frequent extreme weather periods that are challenging to manage but avoid actual load shed events.

These costs tend to be very high because during challenging weather conditions, such as cold snaps, both congestion and fuel costs tend to spike. Wholesale power costs in import-constrained regions often reach scarcity-pricing levels well above $1000/MWh. These high-cost events, incurred during only 1%–5% of all hours in a decade (as documented by the LBNL study discussed above), are not accounted for in any of MISO's Tranche 2.1 benefit metrics, neither the extreme weather metric nor the congestion and fuel cost metric. The Brattle study for NYISO and NYDPS (discussed above) estimated that simulation-based production costs are understated by about 16% due to this type of rare but extreme weather conditions,[57] far higher than MISO's $0.39 billion "low" estimate of extreme weather benefit (which adds only 4.8% to simulated congestion and fuel cost savings). MISO's Tranche 2.1 benefit metrics thus do not fully account for the high costs imposed by extreme weather conditions that do not lead to load shed events—neither in its extreme weather benefit metrics nor in its congestion and fuel cost savings metric.

[57] Newell, Samuel, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015, p. 87.

Q: Why do you believe MISO's estimated $0.076 billion in reduced transmission outage costs are understated?

A: MISO's estimate of how the Tranche 2.1 portfolio may reduce future transmission outage costs of $76 million over 20 years represents less than 1% of MISO's $8.1 billion in estimated congestion and fuel cost savings. This is inconsistent with available data and substantially smaller than transmission outage benefits estimated in other studies. The NYISO Independent Market Monitor has justified a 40% adder to production cost savings from a major New York transmission project because "[t]ransmission outages drive a large share of congestion in market operations."[58] The Brattle study for NYISO and NYDPS (discussed above) estimated that simulation-based production costs are understated by about 18% due to transmission outages that are not captured in such simulations.[59] The high congestion costs caused by transmission outages and the added benefit of reducing these outage-related costs through transmission upgrades is also discussed extensively in the previously-discussed 2021 study that was cited extensively in Order 1920:[60]

- MISO's independent market monitor noted that congestion costs in the 2010 day-ahead and real-time markets rose 54 percent to nearly $500 million due to higher loads and transmission outages.
- A PJM FTR Task Force reporting a $260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year) found that approximately 70% of this revenue inadequacy was due to

---

58 Patton, David, et al., NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects, June 2018, p. 15.

59 Newell, Samuel, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015, p. 87.

60 Pfeifenberger, Johannes, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, pp. 79-82.

major construction-related transmission outages (16%), transmission maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%).

- A 2005 study of PJM showed that without transmission outages, total PJM congestion charges would have been 20% lower.

SPP added the most important transmission outages from a prior year to its forward-looking simulations of transmission investments, finding that it increased the estimates of adjusted production cost savings of new transmission by approximately 11.3%[61] even under normalized system conditions—recognizing that higher additional transmission–outage-related savings would be expected in portions of the grid that already have very limited operating flexibility and during challenging (i.e., not normalized) system conditions.

Q: What is your takeaway about these MISO benefit metrics?

A: The conservatively estimated value of these benefit metrics means that the actual benefits of the Tranche 2.1 projects likely exceed the MISO estimated benefits. It also shows that Dr. Hogan's selective critique of some benefit metrics—and "correcting" them to zero when they cannot possibly be zero—while not considering that other benefit metrics may understate the value of the Board-approved Tranche 2.1 portfolio is unreasonable.

[61] SPP, Regional Cost Allocation Review (RCAR II), July 11, 2016, pp. 51-53.

VIII. DR. HOGAN'S RECOMMENDATION AND THE COMPLAINT'S OVERALL CONCLUSION THAT THE APPROVAL OF TRANCHE 2.1 PROJECTS SHOULD BE REVERSED BECAUSE THESE PROJECTS ARE NOT NEEDED IS INCONSISTENT WITH OTHER STUDIES

Q: Is Dr. Hogan's conclusion that Tranche 2.1 projects are not needed and, thus, should not be approved consistent with the findings of other national and regional transmission needs studies?

A: No. Dr. Hogan's overall recommendation that the approval of Tranche 2.1 projects should be revoked is unreasonable, inconsistent with MISO's increased projected load growth, and inconsistent with both national transmission studies as well as other regions' transmission planning efforts that identify regional and interregional transmission needs across the U.S. and MISO.

Q: Does the U.S. DOE's NTPS include any planning scenarios that are roughly consistent with MISO's projected load growth and clean-energy goals in its footprint?

A: Yes. The 2024 NTPS evaluated a range of scenarios for future transmission needs across the country using a high-level, zonal capacity expansion model, ReEDS. Several of the scenarios roughly align with MISO's F2A resource mix and peak demand assumptions. For instance, one NTPS scenario (referred to as *"AC_DemMd_CurrentPolEP_core"*) reflects a moderate demand growth and current clean energy policies with overall levels similar to those in MISO's F2A.[62]

---

[62] Brown, P., & Mai, T. (2023). National Transmission Planning Study - Long-Term Modeling Results. [Data set]. Open Energy Data Initiative (OEDI). Available at: https://doi.org/10.25984/2460458 The *AC_DemMd_CurrentPolEP_core* scenario has a total installed capacity of 517 GW, with 27% from solar and 35% from wind, and a peak load of 166 GW in 2040. By comparison, the F2A scenario has 471 GW of installed capacity, with similar solar and wind shares, and a peak load of 158 GW in 2042. See resource mix in F2A at MISO, MISO LRTP Futures Review, LRTP Workshop, September 24, 2024, p. 32 and gross peak demand in F2A at MISO, MISO Futures Report: Series 1A, November 1, 2023, p. 31.

In this scenario, the NTPS projects that by 2042 transmission in the MISO Midwest subregion would optimally expand by 12.8–14.6 TW-miles, representing a 45–52% increase relative to MISO's 2025 transmission capabilities.[63] Based on the study's assumed transmission cost of $3,000 per MW-mile, the NTPS estimates the cost of optimal transmission build-out in MISO Midwest is $38–44 billion.[64]

This NTSP result demonstrates that, even with a high-level capacity expansion model that likely underestimates local and lower-voltage transmission needs, a significant amount of transmission upgrades are identified that exceed the total MISO-approved investment costs of LRTP Tranche 1 ($10.3 billion) and Tranche 2.1 ($21.8 billion) projects.[65]

Q: Have other national transmission studies come to similar conclusions?

A: Yes, the DOE also summarized numerous industry studies and scenarios by the national laboratories, the Massachusetts Institute of Technology, and Princeton University in its 2023 DOE Transmission Needs report.[66] The consensus findings based on the summarized studies show that by 2035 regional transmission in the MISO Midwest subregion should be significantly expanded (19% to 174% increase) compared to 2020 transmission capabilities, depending on load growth and clean energy growth assumptions.[67] By 2040,

---

[63] The NTPS refers to the MISO Midwest subregion as MISO Central and MISO North. Brown, P., & Mai, T. (2023). National Transmission Planning Study - Long-Term Modeling Results. [Data set]. Open Energy Data Initiative (OEDI). Available at: https://doi.org/10.25984/2460458

[64] The assumption of $3,000/MW-mile is based on the 2024 DOE NTPS study, p. 30, Figure A-1. In the NREL study "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," the assumed transmission cost was inflated to 2025 dollar using Handy Whitman cost index for transmission. Available at: https://docs.nrel.gov/docs/fy22osti/81644.pdf

[65] MISO, Long Range Transmission Planning, accessed September 6, 2025.

[66] U.S. DOE, National Transmission Needs Study, October 2023.

[67] *Id*., P. ix.

the report identifies that MISO Midwest requires a 29% to 196% increase in transmission compared to 2020 levels.[68]

Q: Are 765 kV transmission additions similar to MISO's Tranche 2.1 projects being identified in other regions of the country?

A: Yes, PJM, ERCOT, and SPP are all planning or actively evaluating similar high-voltage 765 kV transmission as part of their long-term transmission needs.

The PJM Board recently approved $6 billion in transmission projects that include several 765 kV lines to reliably deliver generation to rapidly growing loads in its footprint.[69] The 765 kV lines extend PJM's existing 765 kV transmission system into Virginia, connecting two regions experiencing especially high load growth, the Dominion system in Virginia and the AEP system in Ohio. PJM highlighted the critical role of the 765 kV lines in supporting load growth in this part of their market: "The proposals resolve critical west-east regional transfer reinforcement needs by introducing 765 kV transmission lines connecting the AEP system in the western portion of the PJM footprint with the rest of the network in the central and southern parts of PJM, primarily Virginia."[70]

In ERCOT, where rapid load growth is being driven by the oil & gas industry and data centers, planners have concluded that a 765 kV backbone with 2,468 miles of new transmission lines that spans much of the ERCOT system, similar to Tranche 2.1 in MISO, can most efficiently serve its growing loads.[71] The first phase of the $33 billion Texas

---

68 *Id*., pp. 127-129 Figures VI-4-VI-6.

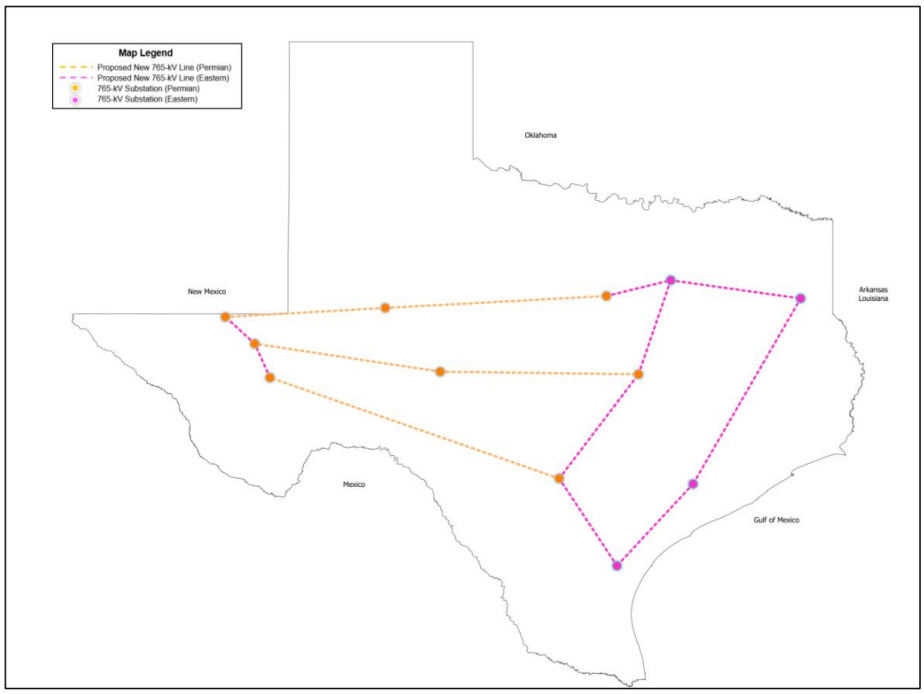
69 PJM Board Approves New Transmission Projects To Support Grid Reliability, and PJM selects regional transmission projects to be jointly developed by Dominion Energy, American Electric Power, FirstEnergy.

70 PJM, PJM Board Approves New Transmission Projects To Support Grid Reliability, February 26, 2025.

71 ERCOT, 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison, January 2025, p. iii.

765 kV Strategic Transmission Expansion Plan (shown in Figure 11 below) was approved by the Texas Commission in April 2025.[72]

FIGURE 11: TEXAS 765-KV STRATEGIC TRANSMISSION EXPANSION PLAN

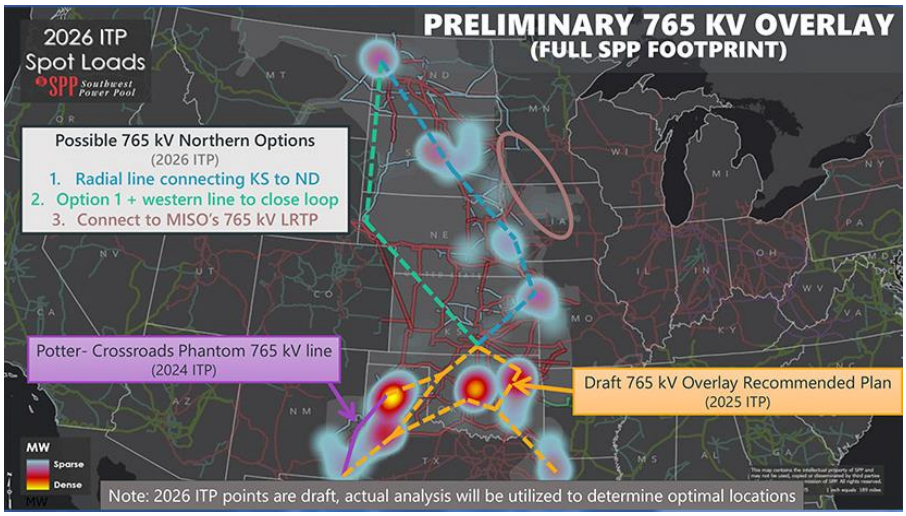


Source: ERCOT, 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison, January 2025.

SPP has similarly been evaluating 765 kV lines in its 2024, 2025, and 2026 long-term planning efforts to deliver generation from resource-rich areas to regional and interregional demand centers as shown in Figure 12 below.

[72] Public Utility Commission of Texas, PUCT Approves Plan for the First Extra High Voltage Transmission Lines in ERCOT Region, News Release, April 24, 2025.

FIGURE 12: SPP 2026 ITP PRELIMINARY 765 KV OVERLAY



Source: RTO Insider, SPP, Members Developing 765-kV Transmission Overlay Plan, Sept 3,2025.

These efforts demonstrate that the need for 765 kV transmission lines is not unique to MISO but part of a broader national trend, where large-scale extra high-voltage transmission is increasingly recognized as the most efficient way to meet rapidly growing demand and associated reliability needs to deliver the necessary electricity from the regions' generating resources.

Q: What is driving these high-voltage, high-capacity transmission projects? Is it primarily to access distant renewable generation?

A: No. These new 765kV projects are primarily driven by high load growth. While SPP and ERCOT also continue to see significant renewable energy development, the main driver of the PJM, ERCOT, and SPP projects are reliability-related transmission needs due to increased load growth. For example, as ERCOT explains:

> [D]emand for electricity is growing exponentially, driven by economic growth and population increase, industrial expansion, electrification of transportation, and growth in data centers and cloud computing. Extra High Voltage (EHV) transmission networks, such as a 765-kV system,

> offer an option to serve this demand more efficiently than lower-voltage networks.

Q: Are the MISO LRTP Tranche 2.1 projects consistent with the results of recent national transmission studies and these regional planning studies?

A: Yes. As discussed above, the scale and type of Tranche 2.1 projects align with the DOE findings covering the MISO Midwest subregion and are consistent with the solutions being advanced in other transmission planning regions that are also experiencing significant load growth.

IX. REGULATORY POLICY IMPLICATIONS

Q: What would the acceptance of Dr. Hogan's analysis and the five states' complaint mean from a regulatory policy perspective?

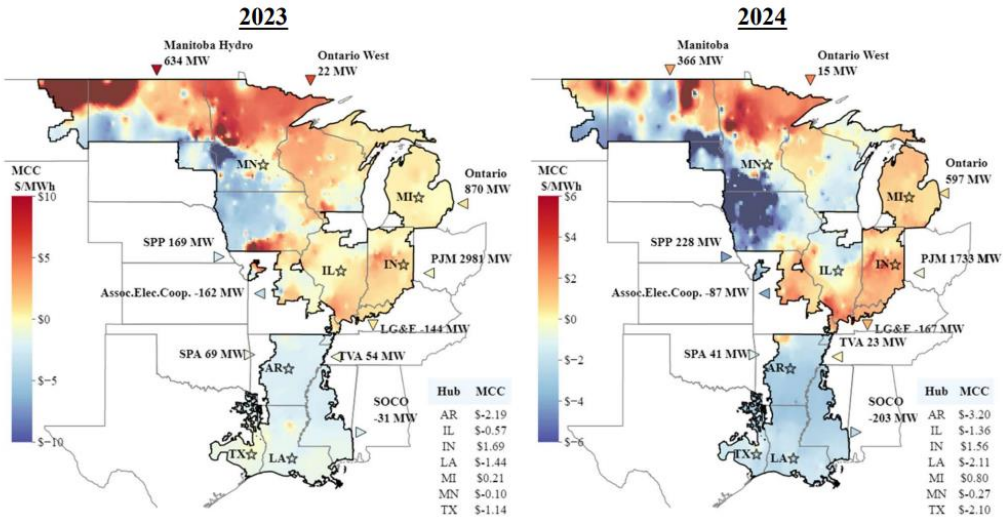
A: We believe that accepting the recommendation of Dr. Hogan would be highly problematic from a regulatory policy perspective as it would allow two states allocated just 2% of Tranche 2.1 costs and three states that are not even allocated any costs for the Tranche 2.1 projects to cancel or delay the development of grid investments needed to address surging new load growth and to more quickly interconnect the necessary generating resources.[73]

The need for these transmission investments is clearly urgent based on recent developments in the MISO market and a number of third-party studies as summarized above. The 2024 State of the Market Report shows that there was $1.8 billion of congestion in the MISO real-time energy market in 2023 and 2024 due to insufficient transmission capacity, resulting in significant differences in market prices across the MISO region, as

[73] Prepared Direct Testimony of Jeremiah Doner at 63.

shown in Figure 13 below.[74] Congestion across MISO will only increase in the future as the system faces larger load growth and continued changes to its resource mix. Congestion results in disparities in costs to ratepayers across the system import-constrained regions (such as northern Minnesota, Wisconsin, Indiana, and Michigan) paying significantly higher wholesale prices for their imports and export-constrained regions (such as Iowa, southern Minnesota, and portions of North Dakota and Montana) getting less for the generation they export. This will tend to increase customer costs in both import and export constrained regions. While some amount of congestion is economically efficient, the significant congestion in recent years creates immediate opportunities for transmission upgrades to reduce these costs.

FIGURE 13: 2023 AND 2024 MISO AVERAGE REAL-TIME CONGESTION COMPONENTS



Source: Potomac Economics, 2024 State of the Market Report for the MISO Electricity Markets, June 2025, p. viii.

At the same time, new generation resources needed to meet growing loads continue to be delayed in entering the market due to the lack of transmission capacity, creating multi-year delays in the generation interconnection queue process and limiting cost-effective new

[74] Potomac Economics, 2024 State of the Market Report for the MISO Electricity Markets, June 2025, p. viii.

entry into the market. Resources that submitted interconnection requests in 2021 have still not completed the necessary interconnection studies. Regional transmission upgrades on the scale of the Tranche 2.1 projects will create significant "headroom" for the interconnection of additional generating resources. These projects are unlikely to eliminate the need to study and identify network upgrades near the point of interconnection but will reduce inefficient, piecemeal transmission upgrades in the future. This will reduce the complexity interconnection studies, and reduce the amount of re-studies required when resources drop out of the interconnection queue, thus speeding up generator interconnection. Further delays in new generation resources ability to connect to the MISO grid will result in higher costs to ratepayers as the queue becomes a significant barrier to entry for cost-effective resources and requires higher-cost resources to operate to serve load.

Rejecting the holistically planned, carefully studied, and already-approved Tranche 2.1 projects would imprudently delay urgently needed transmission infrastructure investments by several years, impede economic growth in MISO's Midwestern subregion, and require many more incremental reliability upgrades, planned in a more piecemeal fashion, that would likely lead to higher costs in the long term and delays for serving load growth across MISO.

Q: Does your testimony imply that the MISO benefit metrics and long-term planning framework Dr. Hogan criticizes cannot or should not be improved?

A: No, not at all. We recognize that MISO's benefit metrics and long-term planning framework can be improved, a fact that MISO acknowledges and has committed to continuing to evaluate opportunities to enhance its LRTP process. Improvements to its

process can be achieved by reviewing its models, assumptions, and methods with stakeholders and reviewing the experience that continues to build across the industry for quantifying the benefits of transmission and analyzing future resource needs with a resource mix that includes higher levels of wind, solar, and battery storage.

However, these improvements should be implemented on a going-forward basis—similarly to how MISO and other regional planners have already been using the experience gained from one planning cycle (or gained by others) to refine and improve the approaches used in the next transmission planning cycle.

Q: Does this conclude your testimony?

A: Yes, it does.

Affidavit of Johannes P. Pfeifenberger

I, Johannes Pfeifenberger, do hereby swear, that I have co-authored the Prepared Direct Testimony of Johannes P. Pfeifenberger and John Michael Hagerty, and the statements contained therein are true and accurate to the best of my knowledge and belief.



Date: Sept 9, 2025

Johannes P. Pfeifenberger

Affidavit of John Michael Hagerty

I, John Micheal Hagerty, do hereby swear, that I have co-authored the Prepared Direct Testimony of Johannes P. Pfeifenberger and John Michael Hagerty, and the statements contained therein are true and accurate to the best of my knowledge and belief.



Date: Sept 9, 2025

John Michael Hagerty

ATTACHMENT A: QUALIFICATIONS OF JOHANNES P. PFEIFENBERGER

Johannes Pfeifenberger is a Principal of The Brattle Group where he is a member of the firm's Utility Regulation and Electric Power practices. He received a M.A. in Economics and Finance from Brandeis University and holds a B.S. and M.S. ("Diplom Ingenieur") in Electrical Engineering, with a specialization in Power Engineering and Energy Economics, from the University of Technology in Vienna, Austria.

Mr. Pfeifenberger is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), and an IEEE Senior Member. He frequently serves as an advisor to research initiatives by the Energy Systems Integration Group (ESIG) and the US Department of Energy's National Labs. Before joining Brattle, he was a Consultant for Cambridge Energy Research Associates and a Research Analyst at the Institute of Energy Economics of the University of Technology in Vienna, Austria.

EDUCATION, AWARDS, AND AFFILIATIONS

- Visiting Scholar, Massachusetts Institute of Technology (MIT), Center for Energy and Environmental Policy Research (CEEPR)
  (2020–present)
- Senior Fellow, Boston University, Institute of Sustainable Energy
  (2020–23)
- Energy Systems Integration Group (ESIG) 2022 Excellence Award
  (for leadership in transmission analysis and reform)
- American Economic Association (AEA),
  Member (2009–present)
- Energy Bar Association (EBA),
  Member (2012–present)
- Institute of Electrical & Electronics Engineers (IEEE),
  Member (1998–present)
  IEEE Senior Member (2022–present)
- United States Association for Energy Economics (USAEE),
  Member (1998–present)
- Brandeis University (1989–91)
  MA in Economics and Finance
- Sophia University (Tokyo, Japan, 1990)
  Program of International Business

- University of Technology (Vienna, Austria, 1983–89)
  BS and MS ("Diplom Ingenieur") in Electrical Engineering, with a specialization in Power Engineering and Energy Economics

TESTIMONY AND REGULATORY FILINGS

Before the Commonwealth of Massachusetts Superior Court, Docket No. 2384-CV-01373, 2384-CV-01376, 2384-CV-01379, 2384-CV-01381, 2384-CV-01382, 2384-CV-01385, on behalf of Plaintiffs (MATEP LLC, MATEP LP, and Longwood Energy Partners LLC), *Expert Report of Johannes P. Pfeifenberger*, November 7, 2024 and *Expert Rebuttal Report of Johannes P. Pfeifenberger*, December 20, 2024.

Before the United States District Court of New Jersey, Docket No. Case No. 16-cv-08445, on behalf of Consolidated Edison Company of New York, Inc., *Expert Report of Johannes P. Pfeifenberger*, December 21, 2022.

Before the Federal Energy Regulatory Commission, Docket No. RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, *Affidavit of Johannes P. Pfeifenberger on Behalf of The Natural Resources Defense Council (NRDC)*, filed by the Public Interest Organizations, August 17, 2022.

Before the Alberta Utilities Commission, Proceeding No. 26911, AESO Bulk and Regional Rate Design and Modernized DOS Rate Design Application, *Written Evidence of Johannes P. Pfeifenberger and John Tsoukalis*, on behalf of Capital Power Corporation, March 28, 2022.

Before the Federal Energy Regulatory Commission, Docket No. ER22-995-000, *Prepared Direct Testimony of Johannes P. Pfeifenberger* on behalf of Midcontinent Independent System Operator, in the matter of Midcontinent Independent System Operator, Inc., and MISO Transmission Owners Proposed Revisions to MISO Tariff to Modify Cost Allocation for Multi-Value Projects, February 4, 2022.

Before the Federal Energy Regulatory Commission, Docket No. RM21-17, *Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs* (with others), report by the Brattle Group and Grid Strategies filed by several parties, October 12, 2021; and *A Roadmap to Improved Interregional Transmission Planning* (with others), report filed by the Natural Resources Defense Council (NRDC), November 30, 2021.

Before the Federal Energy Regulatory Commission, Docket No. ER20-2308, *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty* on behalf of LS Power, *re:* Comments in Support of PJM Stakeholder Approved Section 205 Filing (for treatment of End of Life Projects), July 23, 2020.

Before the Federal Energy Regulatory Commission, Docket No. ER20-1006, re *DATC Path 15*, *Prepared Direct Testimony of Johannes P. Pfeifenberger on behalf of DATC Path 15 LLC*, February 14, 2020.

Before the Federal Energy Regulatory Commission, Docket No. ER20-644-000, *Affidavit of Johannes P. Pfeifenberger and John Tsoukalis* on behalf of Golden Spread Electric Cooperative, *re:* Comments on SPP Compliance Filing Revising Fast Start Pricing Practices, January 21, 2020.

Before the Public Utilities Commission of California, Application 16-10-12, *Ten West Link Economic and Public Policy Benefits and Costs Analysis, Technical Report*, prepared for DCR Transmission LLC (with J. Chang., J.M. Hagerty, M. Tracy, and J.I. Pedtke, December 20, 2019.

Before the Arkansas Public Service Commission (Docket No. 19-035-U), the Texas Public Utilities Commission (Docket No.49737), the Louisiana Public Service Commission (Docket No. U-35324), and the Corporation Commission of Oklahoma (Cause No. PUD 201900048), *Testimonies of Johannes P. Pfeifenberger in the Matter of the Acquisition of Wind Generation Facilities on behalf of Southwestern Public Service Company and Oklahoma Public Service Company*, July 2019 through February 2020.

Before the Public Service Commission of Wisconsin, Docket No. 5-CE-146, *Rebuttal and Sur Surrebuttal Testimony of Johannes Pfeifenberger in Support of the Applicant*, on behalf of American Transmission Company LLC, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project, June 2019.

Before the Federal Energy Regulatory Commission, Docket No. EL19-34-000, *Affidavit and Reply Affidavit of Johannes P. Pfeifenberger and Akarsh Sheilendranath* on behalf of Brookfield Energy Market LP, January 18 and February 25, 2019, Exhibit A to *Complaint and Request for Fast Track Processing of Brookfield Energy Marketing LP*.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Answering Affidavit of Johannes P. Pfeifenberger and Bin Zhou on behalf of PJM Interconnection, L.L.C regarding Cost of Capital*, December 14, 2018, Attachment C to *Answer of PJM Interconnection, L.L.C. to Protests and Comments*, December 17, 2018.

Comments of Pablo Ruiz, James Read, Johannes Pfeifenberger, Roger Lueken, and Judy Chang in Response to the U.S. Department of Energy's Request for Information DE-FOA-0001886, *Expanding Hydropower and Pumped Storage's Contribution to Grid Resiliency and Reliability*, April 4, 2018.

Before the Arkansas Public Service Commission (Docket No. 17-038-U), the Texas Public Utilities Commission (Docket No. 47461), the Louisiana Public Service Commission (Docket No. U-34619), the Corporation Commission of Oklahoma (Cause No. PUD 201700267), and the Federal Energy Regulatory Commission (Docket No. EC18-40), *Direct and Rebuttal Testimonies of Johannes P. Pfeifenberger in the Matter of the Windcatcher Energy Connection Project on behalf of Southwestern Public Service Company and Oklahoma Public Service Company*, June 2017 through January 2018.

Before the Federal Energy Regulatory Commission, ER17-998-000, re *DATC Path 15*, Prepared Direct Testimony of Johannes P. Pfeifenberger on behalf of DATC Path 15 LLC, February 17, 2017.

Before the Federal Energy Regulatory Commission, Docket No. AD16-18-000, *Comments of Mr. Johannes P. Pfeifenberger and Ms. Judy Chang Regarding Competitive Transmission Development Technical Conference*, October 3, 2016.

Before the Cour Supérieure, Province de Québec, District de Montréal, Canada, Case No. 500-17-078217-133, *Expert Report of Johannes Pfeifenberger: CF(L)Co's Sales of "Interruptible" Power*, in Hydro Québec vs. Churchill Falls (Labrador) Corporation Limited, April 17, 2015.

Before the National Energy Board, Canada, Filing A70152, "Market Assessment Report," Annex 2 to ITC Lake Erie Connector LLC (ITC or ITC Lake Erie) Application for an Election Certificate for the Lake Erie Connector Project, May 22, 2015.

Before the Missouri Public Service Commission, File No. EA-2014-0207, "Wind Integration Analysis for the Grain Belt Express HVDC Line," report on behalf of Clean Line Energy Partners, April 13, 2015.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, re *PJM Interconnection, LLC*, Affidavit of Johannes P. Pfeifenberger and Bin Zhou, November 5, 2014. Attachment B to Answer of PJM Interconnection, L.L.C. to Protests and Comments, November 6, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER15-117-100, EL14-99-000 (Not consolidated), re *ISO New England Inc.*, Affidavit of Johannes P. Pfeifenberger, November 5, 2014, Attachment A to Brookfield Energy Marketing LP's Protest and Motion to Intervene, November 6, 2014.

Before the Federal Energy Regulatory Commission, Docket Nos. ER14-33 and ER14-1332, re *DATC Path 15*, Prepared Direct Testimony of Johannes P. Pfeifenberger on behalf of DATC Path 15 LLC, February 18, 2014.

Before the State of Maine Public Utilities Commission, Docket No. 2012-00589 re: *Maine Public Utilities Commission Investigation into Reliability of Electric Service in Northern Maine*, Testimony and Exhibits of Judy Chang and Johannes Pfeifenberger on behalf of Maine GenLead, LLC August 2, 2013; Supplemental Testimony of Judy Chang and Johannes Pfeifenberger, January 17, 2014.

Before the Federal Energy Regulatory Commission (Docket Nos. EC12-145-000 and EL12-107-000, Exhibit No. ITC-600), the Louisiana Public Service Commission (Docket No. U-32538), the Council of the City of New Orleans (Docket No. UD-12-01), the Arkansas Public Service Commission (Docket No. 12-069-U), the Mississippi Public Service Commission (2012-UA-358), and the Public Utilities Commission of Texas (Docket No. 41223), *Direct, Rebuttal, and Sur-Rebuttal (CNA and Arkansas) Testimonies of Johannes Pfeifenberger on behalf of ITC Holdings re: ITC's acquisition of the Entergy Transmission System*, September 2012–August 2013.

Before the Federal Energy Regulatory Commission, Docket No. EL12-98, *Affidavit of Johannes Pfeifenberger on behalf of Hudson Transmission Partners, LLC re: NYISO capacity market offer mitigation*, filed August 3, 2012.

Before the Federal Energy Regulatory Commission, Docket No. EL11-50, Affidavit and Reply Affidavit of Johannes Pfeifenberger on behalf of NRG Energy re: NYISO capacity market offer mitigation, filed September 23 and October 25, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, *Direct Testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine*

Companies re: the Public Policy, Congestion Relief, and Economic Benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Alberta Utilities Commission, Application 1606895, Proceeding ID 1021, Rebuttal Testimony on behalf of AltaLink Management Ltd re: Treatment of Construction Work in Progress, filed April 26, 2011.

Before the Federal Energy Regulatory Commission, Docket No. RM10-10-000, Filed Comments re: Notice of Proposed Rulemaking on Planning Resource Adequacy Assessment Reliability Standard, December 27, 2010 (with K. Carden and N. Wintermantel).

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the Public Policy, Reliability, Congestion Relief, and Economic Benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

Before the Maryland Public Service Commission, Administrative Docket PC22, Filed Comments In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 1, 2010 (with K. Spees).

Before the Federal Energy Regulatory Commission, Docket No. RM10-23-000, Filed Comments re: Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, September 29, 2010 (with P. Fox-Penner and D. Hou).

In the United States District Court for the Eastern District of Pennsylvania, Case No. 08-cv-3649-NS, Expert Report on behalf of PJM Interconnection LLC re: hedge fund trading activities of financial transmission rights, February 22, 2010.

American Arbitration Association, AAA No. 13-198-02918-08, General Electric International, Inc. vs. Project Orange Associates, LLC; Expert Report and Oral Testimony on behalf of General Electric International re: Operating Agreement Dispute, October 12, 2009 and January 5, 2010.

Before the Federal Energy Regulatory Commission, Docket No. AD09-8-000, Filed Comments re: regional transmission planning and cost allocation, December 18, 2009 (with P. Fox-Penner and D. Hou).

Before the Missouri Public Utilities Commission, Case No. ER-2010-0036, Direct Testimony on Interim Rates on Behalf of AmerenUE, October 20, 2009.

Before the Maine Public Utilities Commission, Docket No. 2008-156, *Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation*, Report and Oral Testimony on behalf of Central Maine Power Company and the Industrial Energy Consumer Group, May 2009.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, Direct Testimony on behalf of American Transmission Company re: transmission cost-benefit analysis, January 17, 2008.

Before the Missouri Public Utilities Commission, Case No. EO-2008-0046, Rebuttal, Supplemental Rebuttal, and Surrebuttal Testimony on behalf of Midwest Independent

Transmission System Operator, Inc. re: Aquila RTO cost-benefit analyses, November 30, 2007, December 28, 2007 and February 27, 2008.

Before the Maine Public Utilities Commission, Docket No. 2007-317, *An Assessment of Retail Rate Trends and Generation Costs in Maine*, Whitepaper filed on behalf of Independent Energy Producers of Maine, September 5, 2007 (with A. Schumacher).

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, *Planning Analysis of the Paddock-Rockdale Project*, report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with S. Newell and others).

Before the Alberta Energy and Utilities Board, Proceeding No. 1468565, submission on behalf of AltaLink Management Ltd. re: Benchmarking the Costs and Performance of Utilities using a Uniform System of Accounts, October 2006 (with C. Lapuerta).

Before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, Oral Testimony on behalf of Southern California Edison Company re: economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, September and October, 2006.

Before the Federal Energy Regulatory Commission, Docket No. EL-06097-000, Affidavit and Rebuttal Affidavit on behalf of WPS Resources Corporation re: benefits of implementing a joint and common market across the MISO-PJM service areas, August 15 and October 2, 2006.

Before the Maine Public Utilities Commission, Docket No. 2005-554, Direct Testimony and Surrebuttal on behalf of Penobscot Energy Recovery Company re: retail rate structure for station-use distribution service, June 7 and September 29, 2006.

Before the Colorado Public Utilities Commission, Docket No. 06S-234EG, Direct Testimony on behalf of Public Service Company of Colorado re: purchased power rate adjustment mechanisms and imputed debt of purchased power, April 14, 2006.

In the Matter of Binding Arbitration Between La Paloma Generating Trust, Ltd, as Revocably Assigned to La Paloma Generating Company, LLC, v. Southern California Edison Company, JAMS CASE NO. 1220032122, Direct and Rebuttal Testimony on behalf of Southern California Edison re: Power Contract Dispute, June and July 2005.

Before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, Affidavit and Supplemental Affidavit on behalf of Ameren Services Company re: *Exelon Corporation and Public Service Enterprise Group Incorporated, Joint Application for Approval of Merger*, April 11 and May 27, 2005 (with P. Fox-Penner).

Before the Illinois Commerce Commission, Docket Nos. 05-160, *et al.*, Direct Testimony on Behalf of Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company re: Competitive Procurement of Retail Supply Obligations, February 28, 2005.

Before the Federal Energy Regulatory Commission, Docket Nos. ER04-718-000 *et al.*, Prepared Supplemental Testimony on Behalf of the Michigan Utilities re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with S. Newell).

Before the Federal Energy Regulatory Commission, Docket Nos. ER04-375-002 *et al.*, Declaration re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004; Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities, September 15, 2004 (with S. Newell).

Before the Federal Energy Regulatory Commission, Docket No. ER00-2019-0000, *California Independent System Operator Corporation*, Direct Testimony and Rebuttal Testimony on Behalf of the California Independent System Operator re: Redesign of Transmission Access Charges, February 14, 2003 and October 2, 2003.

Before the Federal Energy Regulatory Commission, Docket No. ES02-53-000, *Midwest Independent Transmission System Operator, Inc.*, Prepared Direct Testimony on Behalf of the Midwest Independent Transmission System Operator re: Rate Design for ISO Administrative Cost Recovery, September 24, 2002.

Before the Federal Energy Regulatory Commission, Docket No. RT01-87-001, *Midwest Independent Transmission System Operator, Inc.*, Affidavit on Behalf of the Midwest Independent Transmission System Operator re: Inter-RTO Coordination, August 31, 2001 (with P. Fox-Penner).

Before the Public Service Commission of the State of Missouri, Case No. EM-96-149, *White Paper on Incentive Regulation: Assessing Union Electric's Experimental Alternative Regulation Plan*, on behalf of Ameren Services Company, February 1, 2001 (with D. Sappington, P. Hanser, and G. Basheda).

Before the Federal Energy Regulatory Commission, Docket No. ER00-2019-0000, *California Independent System Operator Corporation*, Testimony before Settlement Judge on behalf of the California ISO re: Redesign of Transmission Access Charges, July 12 and August 10, 2000.

Before the State of New York Public Service Commission, *In the Matter of Customer Billing Arrangements*, Case 99-M-0631, Affidavit on behalf of New York State Electric and Gas Corporation, April 19, 2000 (with F. Graves).

Before the Federal Communications Commission, "An Economic Assessment of the Risks and Benefits of Direct Access to INTELSAT in the United States," Report filed *In the Matter of Direct Access to the INTELSAT System*, IB Docket No. 98-192, File No. 60-SAT-ISP-97, December 21, 1998 (with H. Houthakker and J. Green).

Before the Federal Communications Commission, "A Response to the Economists Inc. Study: Preliminary Competition Analysis of Proposed Lockheed Martin/COMSAT Transaction," December 1998 (with C. Lapuerta).

Before the United States District Court, Central District of California, Expert Report of *The Brattle Group* re: Contract Termination Damages; *Comsat Corporation v. The News Corporation, Limited, et al.*, July 1, 1998.

Before the Federal Communications Commission, "Response to Comments on Comsat's Reclassification Petition," File No. 60-SAT-ISP-97, July 7, 1997 (with H. Houthakker and W. Tye).

Before the Federal Communications Commission, "The Economic Basis for Reclassification of Comsat as a Non-Dominant Carrier," Report filed *In the Matter of Comsat Corporation Petition for Forbearance from Dominant Carrier Regulation and for Reclassification As a Non-Dominant Carrier*, April 24, 1997 (with H. Houthakker and W. Tye).

Before the Federal Communications Commission, "Competition in Transoceanic Switched Voice and Private Line Services to and from the U.S.: 1997 Update," Report filed *In the Matter of Comsat Corporation Petition for Forbearance from Dominant Carrier Regulation and for Reclassification As a Non-Dominant Carrier*, April 23, 1997 (with H. Houthakker and W. Tye).

Before the Federal Communications Commission, *Response to Statement of Professor Jerry A. Hausman*, in *re Hughes Communications, Inc.*, File Nos. 2-SAT-AL-97(11), *et al.*, December 19, 1996 (with W. Tye).

Before the Federal Communications Commission, *The Economic Implications of the Proposed Hughes-PanAmSat Transaction*, Written Statement in re *Hughes Communications, Inc.*, File Nos. 2-SAT-AL-97(11), *et al.*, December 2, 1996 (with W. Tye).

Before the Federal Communications Commission, "Competition in the Market for Trans-Oceanic Video Services to and from the U.S.," Report filed *In the Matter of Comsat Corporation Petition for Partial Relief from the Current Regulatory Treatment of Comsat World Systems' Switched Voice, Private Line, and Video and Audio Services*, Docket No. RM-7913, October 24, 1996, (with H. Houthakker and W. Tye).

Before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Telecommunications and Finance, *Oversight Hearing on the Restructuring of the International Satellite Organizations*, Written Testimony, September 25, 1996.

Before the Federal Communications Commission, "Competition in the Market for Trans-Oceanic Facilities-Based Telecommunications Services," Report filed *In the Matter of Petition for Partial Relief From the Current Regulatory Treatment of COMSAT World Systems' Switched Voice, Private Line, and Video and Audio Services*, Docket No. RM-7913, June 24, 1994 (with H. Houthakker and W. Tye).

Before the State of New York Public Service Commission, *Fuel Switching and Demand Side Management*, Prepared Written Testimony on behalf of National Fuel Gas Distribution Company, Case Nos. 28223 and 29409, September 1992 (with D. Weinstein).

Mr. Pfeifenberger has also presented research findings related to mergers and network access matters to government and antitrust enforcement agencies, including the U.S. Department of Justice, the Merger Task Force of the European Community, the German Cartel Office, the German Ministry of Economics, and the White House National Economic Council.

ARTICLES, REPORTS AND PRESENTATIONS

Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals (with L. Lam, K. Graham, et al.), prepared for the Clean Air Task Force (CATF), July 22, 2025.

Regional and Interregional Transmission Planning in the Northeastern US, prepared for the Vermont System Planning Committee, July 16, 2025.

Annual US Transmission Investments 1996–2024, prepared for the Federal Energy Regulatory Commission (FERC), June 11, 2025.

West Wide Story Panel Discussion: An Overview of Day-Ahead Market Participation Benefits Study Results (with K. Van Horn, J. Tsoukalis, et al.), prepared for the California Community Choice Association (CalCCA) Annual Conference, Irvine, CA, April 29, 2025.

Strategic Action Plan: Overview (with J. DeLosa III and K. Graham), Webinar, prepared for the Northeast States Collaborative on Interregional Transmission, April 29, 2025.

Strategic Action Plan (with J. DeLosa III and K. Graham), prepared for the Northeast States Collaborative on Interregional Transmission, April 28, 2025.

Accelerating the Integration of New Co-located Generation and Loads (with A. Levitt and A. Mohan), prepared for Bloom Energy, April 23, 2025.

Intertie Optimization: Achieving Efficient Use of Interregional Transmission, presented at the IEEE Energy and Policy Forum, April 16, 2025.

Meeting Unprecedented Load Growth: Challenges & Opportunities (with S. Newell and R. Hledik), white paper, April 14, 2025.

Market Benefits and Seams: Options and Implications (with J. Tsoukalis and K. Van Horn), presented at the WEIM Regional Issues Forum, April 9, 2025.

Day-Ahead Market Participation Benefits Studies for EPE: Sensitivity: EPE in Markets+ & PNM in EDAM with Eddy Tie Value (with J. Tsoukalis, K.Van Horn, et al.), prepared for the El Paso Electric Company, March 13, 2025.

Proposal to Develop Optimal Transmission Planning in Alberta (with J. Tsoukalis, J. M. Hagerty, T. Chapman, and P. Heller), prepared for AESO, March 2025.

Intertie Optimization: Achieving Efficient Use of Interregional Transmission (with N. Bay and J. DeLosa III), presented to FERC Staff, February 26, 2025.

Strategic Action Plan, Phase 1: Study Synthesis of Transmission Needs (with J. DeLosa III and K. Graham), prepared for Northeast States Collaborative on Interregional Transmission, February 25, 2025.

Market and Operational Benefits of HVDC Transmission, prepared for Western Clean Energy Advocates Transmission Working Group, February 5, 2025.

Future Energy & Resource Needs Study (FERNS) (with K. Peters, S. Willett, et al.), prepared for the Southwest Power Pool, February 2025.

Preliminary Day-Ahead Market Impacts Study: Impact of Market Footprints on California Customers (with J. Tsoukalis, K. Van Horn, E. Bennet, and A. Savage Brooks), prepared for the State of California Energy Commission, Docket No. 24-IEPR-01, January 24, 2025.

Transmission Cost Allocation for Order 1920 Compliance, presented at NARUC-NASEO-DOE Webinar on FERC Order 1920: Taking Action on Transmission Planning and Cost Allocation, December 6, 2024.

Ensuring Cost Effective Transmission to Support Affordable State Electricity Policies, presented at the 2024 NARUC Annual Meeting and Education Conference, Ahaheim, CA, November 13, 2024.

Order 1920 Compliance: *An Opportunity to Improve Transmission Planning beyond Mandates*, presented at Energy Systems Integration Group (ESIG) 2024 Fall Technical Workshop, Providence. RI, October 22, 2024.

Pathways to Coordination: Proactive, State-Led Transmission Development to Reduce Costs and Achieve Goals in PJM (with J. Delosa III and T. Paradise), prepared for the American Council on Renewable Energy (ACORE), October 17, 2024.

Transmission Policy: Frameworks for Efficient Investments and Interprovincial, International Expansion, presented at Ivey Energy Policy and Management Centre, 8th Annual Workshop on the Economics of Electricity Policy and Markets, October 15, 2024.

Cost-Effective Transmission between Canada and the US Northeast (w. K. Graham)*,* presented at Bridging the Power Gap Webinar: How Bidirectional Clean Energy Benefits the US Northeast and Eastern Canada, hosted by Acadia Center, Environmental League of Massachusetts (ELM), and New England for Offshore Wind, October 9, 2024.

BPA Day-Ahead Market Participation Benefits Study (with J. Tsoukalis, K. Van Horn, et al.), prepared for Gridlab, NIPPC, NW Energy Coalition, PNGC Power, Renewable Northwest, October 9, 2024

Comments on Powerex Response to our Paper on Day-Ahead Markets in the WECC, October 2024.

The Proposed Day-Ahead Markets in the WECC: A Comparative Assessment of EDAM and Markets+ Design Features (with J. Tsoukalis, O. Kuzura, and K Van Horn), White Paper prepared for PacifiCorp, October 1, 2024.

*"*Planning for the Winds of Change: Coordinated and Proactive Offshore Wind Transmission Planning in Europe, China, and the United States*"* (with A. Orths, W. Wang and J. DeLosa III) *IEEE Power and Energy Magazine,* vol. 22, no. 5*,* pp. 20–30, September 20, 2024*,* doi: 10.1109/MPE.2024.3402670.

New Mexico Day-Ahead Market Participation Benefits Studies: Comparative Benefits for EPE and PNM of Joining EDAM or Markets+ (with J. Tsoukalis, K. Van Horn, et al.), presented for New Mexico Public Regulation Committee*,* August 29, 2024.

Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid (with J.M. Hagerty, et al. and Grid Strategies LLC), August 27, 2024.

Enduring Cost-Effective Transmission in Support of a Clean Energy Transition, presented to New England States Committee on Electricity (NESCOE), August 9, 2024.

Future Energy and Resource Needs Study (Ferns): Preliminary Update (w. K. Peters), prepared for SPP Strategic Planning Committee, July 18, 2024.

SPP Future Energy and Resource Needs Study (FERNS): Land Use Analysis Approach: Summary for ESWG (w. S. Willet and K. Peters), presented to the Economic Studies Working Group (ESWG), June 27, 2024.

Economic Review and Outlook for Eastern U.S. Offshore Wind Generation, presented at Advanced Energy United—Eastern Commissioners Forum on Offshore Wind Transmission, June 20, 2024.

Annual US Transmission Investments 1996–2023 (with other from The Brattle Group), June 13, 2024

Illinois Renewable Energy Access Plan: Enabling an Equitable, Reliable, and Affordable Transition to 100% Clean Electricity for Illinois (with others from The Brattle Group, Staff of Illinois Commerce Commission, and Great Lakes Engineering), May 30, 2024.

Market Benefits and Seams: Options and Implications (w J. Tsoukalis and K. Van Horn), presented at Spring 2024 Joint CREPC-WIRAB Meeting, Denver, CO, April 24, 2024.

Intertie Optimization: Efficient Use of Interregional Transmission (Update) (with Norman Bay), prepared for Organization of PJM States, Inc. (OPSI), April 12, 2024.

Optimal Expansion and Use of Interregional Transfer Capability, prepared for Minnesota Public Service Commission, April 5, 2024.

NV Energy Day-Ahead Market Benefit Studies: Comparative Benefits for NV Energy of Joining EDAM vs. Markets+ (with J. Tsoukalis, K. Van Horn, et al.), presented for Public Utilities Commission of Nevada, April 3, 2024.

Proactive Transmission Planning for a Clean Energy Transition, presented at Altantic Global Energy Center, Private Roundtable: Innovative planning and finance solutions for energy infrastructure, Washington DC, March 28, 2024.

Interregional Transmission Planning with HVDC, prepared for Energy Systems Integration Group, ESIG Webinar, March 19, 2024.

Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S. (with J. Delosa III and P. L. Joskow)*,* MIT CEEPER Working Paper Series, February 2024 CEEPR WP 2024-03, March 5, 2024. Are Firm Capacity Requirements Outpacing Replacements?, prepared for Future Power Markets Forum, January 25, 2024.

The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission (with J. Delosa III, J. Gonzalez, N. C. Bay, and V. W. Chum), prepared for ACORE, Advanced Power Alliance, Grid United, Invenergy, MAREC Action, and NRDC, presented at MGA Mid-Grid Webinar, December 14, 2023.

The Operational and Market Benefits of HVDC to System Operators (with C. M. Sonnati), presented at the ESIG Fall Technical Workshop, October 23, 2023.

How Resources Can be Added More Quickly and Effectively to PJM' s Grid, prepared for Organizatrion of PJM States, Inc. (OPSI), presented at 2023 Annual Meeting, Covington, KY, October 15–18, 2023.

The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission (with J. Delosa III, J. Gonzalez, N. C. Bay, and V. W. Chum), prepared for ACORE, Advanced Power Alliance, Grid United, Invenergy, MAREC Action, and NRDC, October 2023. Presentation: ESIG Webinar, October 2, 2023.

Electricity pricing challenges in future renewables-dominant power (with D. S. Mallapragada, C. Junge , C. Wang, P. L. Joskow, and R. Schmalensee, *Energy Economics*, Vol. 126, October 1, 2023, 106980 (https://doi.org/10.1016/j.eneco.2023.106981).

The Value of Interregional Transmission: Grid Planning for the 21st Century, prepared for Midwestern Governors Association MID-GRID 2023 Meeting, Little Rock, AR, September 27–28, 2023.

U.S. Offshore Wind Transmission: Holistic Planning and Challenges, presented at Massachusetts Clean Energy Transmission Working Group, September 22, 2023.

The Operational and Market Benefits of HVDC To System Operators (with L. Bai, A. Levitt, C. A. Plet and C. M. Sonnathi), prepared for GridLab, American Council on Renewable Energy, Clean Grid Alliance, Grid United, Pattern Energy, and Allete, September 2023. Presentation: *The Operational and Market Benefits of HVDC to System Operators* (with C.A. Plet), presented at ACORE Webinar, September 19, 2023.

Extended Day-Ahead Market Participation Benefits Study (with J. Tsoukalis, K. Van Horn, and E. Bennett, prepared for Balancing Area of Northern California, Idaho Power Company, Los Angeles Department of Water and Power, PacifiCorp, and Sacramento Municipal Utility District, December 2023.

Extended Day-Ahead Market Benefit Study (with J. Tsoukalis and E. Bennett), prepared for the EDAM Forum, Las Vegas, NV, August 30, 2023.

Annual U.S. Transmission Investments 1996–2022, for the Federal Energy Regulatory Commission, July 31, 2023.

HVDC Transmission: Multi-Value Planning Considerations and Experience (with L. Bai), prepared for Grid United, MISO PAC Meeting, May 31–June 1, 2023.

South Carolina Electricity Market Reform Measures Study: Final Report Presentation (with J. Tsoukalis, K. Spees, A. Levitt, and A. W. Thompson), presented to the South Carolina Electricity Market Reform Measures Study Committee, May 1, 2023.

Assessment of Potential Market Reforms for South Carolina's Electricity Sector (with J.H. Tsoukalis, K. Spees, A. Levitt, A. W. Thompson, O. Kuzura, E. Bennett, S. Phan, M. Diehl, E. Curtis, S. Tang, and R. Nelson), prepared for the South Carolina General Assembly, April 27, 2023.

Brattle EDAM Simulations: PacifiCorp Results (with J. Tsoukalis and E. Bennet), prepared for PacifiCorp, April 2023, presented before the Public Service Commission of Utah in Docket No. 23-9899-01, Notice of Technical Conference, April 26, 2023.

U.S. Offshore Wind Transmission: Policy and Regulatory Challenges, presented at the 2023 MIT Energy Initiative Spring Symposium, March 22, 2023.

Why and How to Start Planning for Offshore Wind Transmission: Reducing Costs and Community & Environmental Impacts, presented at the Advanced Energy Institute—Eastern Commissioners Forum on Offshore Wind Transmission, March 17, 2023.

The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals, presented at the ACORE Report Release Webinar, January 24, 2023.

The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals (with J. DeLosa III, L. Bai, C. Plet (DNV), C. Peacock, R. Nelson), prepared for Natural Resources Defense Council, GridLab, Clean Air Task Force, American Clean Power Association, and American Council On Renewable Energy, January 24, 2023.

Illinois Renewable Energy Access Plan: Enabling an Equitable, Reliable,and Affordable Transition to 100% Clean Electricity for Illinois, Second Draft for Commission Consideration (with Illinois Commerce Commission Staff, The Brattle Group, and Great Lakes Engineering), prepared for the Illinois Commerce Commission, December 2022.The Future of Energy Storage: Insights from MIT's Study, MIT Center for Energy and Environmental Policy Research, Fall 2022 Research Workshop, November 17–18, 2022.

New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report (with J.M. Hagerty, J. Delosa, S. Herling, M. Kalpin, D. Sullivan, C. Peacock, E. Bennett, and E. Snyder), prepared for the New Jersey Board of Public Utilities, October 26, 2022.

Transmission Planning for a Changing Generation Mix (with J. Delosa), prepared for Organization of PJM States, Inc. (OPSI), 2022 Annual Meeting, Indianapolis, IN, October 18, 2022.

Net Zero Market Challenges, prepared for AESO Economics Excellence Conference, September 27, 2022.

Comments on LBNL's Empirical Assessment of Regional and Interregional Transmission Congestion Value, prepared for Energy Systems Integration Group (ESIG) Webinar, August 25, 2022.

Promoting Efficient Investment in Offshore Wind Transmission, presented at DOE-BOEM Atlantic Offshore Wind Transmission Economics & Policy Workshop, August 16, 2022.

Generation Interconnection and Transmission Planning, prepared for ESIG Special Topic Workshop, August 9, 2022.

Illinois Renewable Energy Access Plan: Enabling an Equitable, Reliable, and Affordable Transition to 100% Clean Electricity for Illinois (The Brattle Group, Illinois Commerce Commission Staff, and Great Lakes Engineering), First Draft for Public Comment, prepared for the Illinois Commerce Commission, July 2022.

New York Power Grid Study and Regional Challenges, presented at Northeast Clean Energy Council (NECEC) Northeast Grid Infrastructure Planning Summit, New York, June 23, 2022.

Proactive, Scenario-Based, Multi-Value Transmission Planning (with J. Delosa), presented to PJM Long-Term Transmission Planning Workshop, June 7, 2022.

The Future of Energy Storage, an Interdisciplinary MIT Study (contributing author with others), June 3, 2022.

Planning for Generation Interconnection, prepared for ESIG Special Topeic Webinar: Generation Interconnection Criteria, May 31, 2022.

A Transmission Blueprint for New England: Delivering on Renewable Energy (with Renew Northeast, Boreas Renewables LLC, and J. Delosa), May 23, 2022.

Solving the Transmission Challenge for Decarbonization, prepared for New England Conference of Public Utilities Commissioners (NECPUC) 74th Symposium, May 23, 2022.

New York Power Study: Results and Observations, presented at Independent Power Producers of New York 36th Annual Spring Conference, May 18, 2022.

PJM CONE 2026/2027 Report (with S. A. Newell, J. M. Hagerty, B. Zhou, T. Carless, R. Janakiraman, S.H. Gang, P. S. Daou, and J. C. Junge), prepared for PJM Interconnections, April 21, 2022.

Electricity Sector Policy Reforms to Support Efficient Decarbonization (with H.K. Gruenspecht, P.L. Joskow, and R. Schmalensee), MIT Center for Energy and Environmental Policy Research Working Paper Series, CEEPR WP 2022-007, April 2022.

New York State and Regional Transmission Planning for Offshore Wind Generation, presented at NYSERDA Offshore Wind Webinar, March 30, 2022.

The Benefits of Interregional Transmission: Grid Planning for the 21st Century, presented at the U.S. Department of Energy's (DOE's) National Transmission Planning Study Webinar, March 15, 2022.

The Electricity Grid's Role in Achieving Carbon Neutrality in the U.S. and New England, presented to Solving for Carbon Neutrality at MIT, February 28, 2022.

Generation Interconnection and ELCC Values for Variable Resources, prepared for OPSI Staff Call, February 25, 2022.

Support for MISO MVP Subregional Cost Allocation, prepared for MISO RECB Meeting, January 24, 2022.

21st Century Transmission Planning: Benefits Quantification and Cost Allocation, presented to the NARUC members of the Joint Federal-State Task Force on Electric Transmission, January 19, 2022.

A Roadmap to Improved Interregional Transmission Planning (with K. Spokaras, J. M. Hagerty, and J. Tsoukalis), prepared with funding from the Natural Resources Defense Council (NRDC), November 30, 2021.

Electricity Price Distributions in Future Renewables-Dominant Power Grids and Policy Implications (with D.S. Mallapragada, C. Junge, C. Wang, P.L. Joskow, and R. Schmalensee), MIT Center for Energy and Environmental Policy Research Working Paper Series, CEEPR WP 2021-017, November 29, 2021.

The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York (with J. Tsoukalis and S.A. Newell), prepared with Siemens and Hatch for NYSERDA, November 9, 2021.

FERC ANOPR Reform: The Need for Improved Transmission Planning and Cost Allocation, presented to Power Markets Today Seminar, November 3, 2021.

Transmission—The Great Enabler: Recognizing Multiple Benefits in Transmission Planning, presented to ESIG Fall Workshop: Closing Plenary Session, October 28, 2021.

Energy Vision: A clean energy future for Australia (with others), published by Transgrid, October 14,2021.

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (with K. Spokas, J.M. Hagerty, J. Tsoukalis, R.Gramlich, M. Goggin, J. Caspary, and J. Schneider), The Brattle Group and Grid Strategies, October 13, 2021.

A Call for More Pro-Active, Multi-Value Transmission Planning, Energy Systems Integration Group (ESIG), September 21, 2021.

Transmission Investment Needs and Challenges (with J. Tsoukalis). Presented at JP Morgan Renewables and Grid Transformation Series, June 1, 2021.

Congestion Mitigation with Topology Optimization: Case Studies and a Path Toward Implementation (with P. Ruiz). Presented at the Organization of MISO States and Midwestern Governors Association's Americas Smartland Discussion Webinar*,* June 1, 2021.

Transmission Options for Offshore Wind Generation. Presented at NYSERDA Offshore Wind Webinar, May 12, 2021.

Transmission Planning and Benefit-Cost Analyses, Presented to FERC Staff, April 29, 2021.

New York Power Grid Study: Transmission Implications. Presented at New York's Clean Energy Agenda for Building a Green Economy | New York State Bar Association, Environmental & Energy Law Section, April 14, 2021.

Enabling Cost-Effective Energy Efficiency in the Midcontinent ISO Resource Adequacy Construct: The Advantages of a Supply-Side, Gross Accounting Framework (with K. Spees and P. Jones). Prepared for Advanced Energy Economy, April 2021.

The Benefits of Energy Efficiency Participation in Capacity Markets (with K. Spees, and W. Graf). Prepared for Advanced Energy Economy, April 2021.

The Electricity Grid's Role in Achieving Carbon Neutrality in the US and New England. Presented to Solving for Carbon Neutrality at MIT, March 17, 2021.

SWIP-N Transmission Benefits Analysis (with M. Hagerty and E. Bennett). Presented for Great Basin Transmission, February 2021

Offshore Wind Transmission: An Analysis of New England and New York Offshore Wind Integration (with S. A. Newell, W. Graf, and K. Spokas). Presented at the Northeast Regional Ocean Council & Mid-Atlantic Regional Council on the Ocean Webinar, February 5, 2021.

Initial Report on the New York Power Grid Study (with S. A. Newell, A. Sheilendranath, S. Crocker Ross, S. Ganjam, R. Austria, and K. Dartawan). Prepared for the New York State Public Service Commission, January 19, 2021.

Western Energy Imbalance Service and SPP Western RTO Participation Benefits (with J. Tsoukalis, M. Celebi, S. Leamon, C. Peacock, and S. Ganjam). Prepared for Southwest Power Pool, December 2, 2020.

Electricity Transmission and Railroads: A Synergy of Needs and Right-Of Ways (with M. Hagerty). Presented at Rail Electrification Council Annual Meeting, November 19, 2020.

Transmission Cost Allocation: Principles, Methodologies, and Recommendations. Prepared for OMS Cost Allocation Principles Committee Meeting, November 16, 2020.

Offshore Wind Transmission: An Analysis of Planning in New England and New York (with W. Graf). Presented to Clean Energy States Alliance, October 23, 2020.

The Value of Diversifying Uncertain Renewable Generation through the Transmission System: Cost Savings Associated with Interconnecting Systems with High Renewables Generation (with P. Ruiz and K. Van Horn). Presented for BU Institute for Sustainable Energy Webinar Series, October 14, 2020.

The Value of Diversifying Uncertain Renewable Generation through the Transmission System (with P. Ruiz and K. Van Horn). Published by Boston University's Institute for Sustainable Energy (BU-ISE), September 2020.

Offshore Wind Transmission: An Analysis of Options for New York (with S. Newell, W. Graf and K Spokas), Prepared for Anbaric, August 2020.

Considerations for Meeting Sub-Annual Needs and Resource Accreditation across RTOs (with S. Newell, M. Hagery, and W. Graf), prepared for MISO Resource Adequacy Subcommittee, July 8, 2020.

Energy-Market Payment Options for Demand Response in Ontario (with K. Spees, L. Lam, S. Leamon, and J. Moraski), prepared for IESO, May 21, 2020.

Offshore Transmission in New England: The Benefits of a Better-Planned Grid (with S. Newell and W. Graf), prepared for Anbaric, May 2020.

The Evolving Landscape for Storage: Wholesale Market, T&D, and Customer Benefits (with R. Lueken), prepared for MIT Energy Initiative Electric Power Systems Center Spring Workshop, May 13, 2020.

Industry Changes in Resource Adequacy Requirements, Metrics, and Design Elements, (with S. Newell, M. Hagery, and W. Graf), prepared for MISO Resource Adequacy Subcommittee, May 6 and May 20, 2020.

Forward Clean Energy Markets: A New Solution to State-RTO Conflicts (with K. Spees and S. Newell), Utility Dive, January 27, 2020.

Ten West Link Economic and Public Policy Benefits and Costs Analysis: Technical Report (with J.W. Chang, J.M. Hagerty, M. Tracy, and J. Imon Pedtke), prepared for DCR Transmission, L.L.C., December 20, 2019.

U.S. Offshore Wind: Status, Project Development, and Transmission Considerations, Presented to Harvard Electricity Policy Group 97th Plenary Session (with S. Newell and K. Spokas), December 13, 2019.

Solar-Plus-Storage: The Future Market for Hybrid Resources (with R. Hledik, R. Lueken, J. Chang, J. Cohen, and J. Imon Pedtke), December 2019.

Cost Savings Offered by Competition in Electric Transmission, Presented during Power Markets Today Webinar, December 11, 2019.

The Value of Hydro and Battery Storage in Transforming Wholesale Power Markets, Prepared for MIT's Future of Storage Team (with R. Lueken), December 4, 2019.

Improving Transmission Planning: Benefits, Risks, and Cost Allocation, Presented at MGA's Ninth Annual Transmission Summit, November 6, 2019.

U.S. Offshore Wind Generation, Grid Constraints, and Transmission Needs, Presented at Offshore Wind Transmission, USA Conference (with S. Newell and K. Spokas), September 18, 2019.

Response to Concentric Energy Advisors' Report on Competitive Transmission, prepared for LSP Transmission Holdings, LCC (with J. Chang, M. Hagerty, and J. Cohen), August 2019.

Capacity Markets and Wholesale Market Outcomes, presented at NBER Economics of Electricity Markets and Regulation Workshop, Incline Village, Nevada, May 28, 2019.

Cost Saving Offered by Competition in Electric Transmission: Experience to Date and Potential Value for Electricity Customers, presented to Energy Bar Association (with J. Chang and J.M. Hagerty), May 7, 2019.

Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, Commissioned by the North Carolina Clean Energy Business Alliance, Carolina Utility Customers Association, and Conservatives for Clean Energy—North Carolina (with J. Chang and J. Tsoukalis), April 2019.

Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, prepared for LSP Transmission Holdings, LLC (with J. Chang, A. Sheilendranath, J. M. Hagerty, S. Levin, and W. Jiang), April 2019

Integrating Renewables into Lower Michigan's Electricity Grid: Resource Adequacy and Operational Analysis and Implications, prepared for DTE Energy (with J. W. Chang, K. Van Horn, A. Sheilendranath, A. Kaluzhny, and C. Bourbonnais), March 29, 2019

The Changing Role of Hydro Power in Transforming Wholesale Power Markets, presented at Canadian Hydropower Association Forum 2018, Ottawa, ON (with J. Chang, P. Ruiz), November 21, 2018.

Transmission Solutions: Potential Cost Savings Offered by Competitive Planning Processes, presented at 2018 National Association of Regulatory Utility Commissioners (NARUC) Annual Meeting, Orlando, FL (with J. Chang, A. Sheilendranath), November 13, 2018.

Energy Markets and Water Power: Square Peg in a Round Hole?, presented at Power of Water, Canada Conference & Trade Show, Niagara on the Lake, Ontario, October 30, 2018.

Transmission Competition Under FERC Order No. 1000 at a Crossroads: Reinforce or Repeal?, prepared for LSP Transmission Holdings, GridLiance, presented to American Public Power Assocation, 2018 L&R Conference, Charleston, SC (with J. Chang, A. Sheilendranath), October 10, 2018.

The Economic Potential for Energy Storage in Nevada, prepared for Public Utilities Commission of Nevada, Nevada Governor's Office of Energy (with R. Hledik, J. Chang, R. Lueken, J. I. Pedtke, and J. Vollen), October 1, 2018.

Initial Comments on SPP's Draft Ramp Product Report, prepared for Golden Spread Electric Cooperative, Inc. (with J. Tsoukalis, J. Chang, and K. Spees), August 30, 2018.

Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively, Discussion Paper (with K. Spees, S. Newell, and J. Chang), July 30, 2018.

Various reports, memoranda, and presentations prepared for the Alberta Electricity System Operator (AESO) in support of the AESO's efforts of developing a forward capacity market, (with others; posted on the AESO website), 2016-2018.

Various reports and memoranda prepared for the Ontario Independent Electricity System Operator (IESO) in support of the IESO's efforts of developing an incremental capacity auction, (with others; posted on the IESO website), 2016-2018.

Market and Regulatory Advances in Electricity Storage, presented at MIT CEEPR Spring 2018 Workshop (with J. Chang and R. Luecken), May 25, 2018.

U.S. Offshore Wind Generation and Transmission Needs, Presented at the Offshore Wind Transmission USA Conference (with J. Chang and D. Jang), May 23, 2018.

PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, prepared for PJM (with S. Newell, M. Hagerty and others), April 19, 2018.

Fourth Review of PJM's Variable Resource Requirement Curve, prepared for PJM (with S. Newell, D.L. Oates and others), April 19, 2018.

Maximizing the Market Value of Flexible Hydro Generation, presentation (with P. Ruiz, J. Read, J. Chang, and R. Lueken), March 29, 2018.

Opportunities for Storage Under FERC Order 841, Presented at Energy Storage Association's (ESA) Webinar "Kicking the Tires on Order 841: Diving into Details, Opportunities, and Challenges" (with J. Chang and R. Lueken), March 28, 2018.

Hello World: Alberta's Capacity Market: Features Requiring Tradeoffs, Prepared for 2018 IPPSA Conference (with J. Chang and K. Spees), March 18, 2018.

Getting to 50 GW? The Role of FERC Order 841, RTOs, States, and Utilities in Unlocking Storage's Potential, The Brattle Group (with J. Chang, R. Lueken, P. Ruiz, Roger Lueken, and H. Bishop), February 22, 2018.

Market Power Screens and Mitigation Options for AESO Energy and Ancillary Service Markets, Prepared for Alberta Electricity System Operator (with R. Broehm, J. Chang, M.G. Aydin, C. Haley, and R. Sweet, January 26, 2018.

Modeling the 1-Step and 2-Step Dispatch Approaches to Account for GHG Emissions from EIM Transfers to Serve CAISO Load, Prepared for the California ISO (with J. Chang, K. Van Horn, O. Aydin, and M. Geronimo Aydin), November 17, 2017.

Modelling Enhancements for CAISO Transmission Planning, Prepared for LS Power (with J. Chang, K. Van Horn, M. Hagerty, J. Imon Pedtke, and J. Cohen), October 06, 2017.

Flexibility Enhancements: Alberta Needs and Experience from Other Jurisdictions, Prepared for the Alberta Electricity System Operator (with K. Spees, J. Chang, Y. Yang, R. Carroll, R. Lueken, and C. McIntyre), August 15, 2017.

Advancing Past "Baseload" to a Flexible Grid: How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix, Prepared for NRDC (with J. Chang, M. Geronimo Aydin, and others), June 26, 2017; Presented to the Senate Energy & Natural Resources Committee on July 28, 2017.

Well-Planned Transmission to Integrate Customer Needs and Resources, Presented at WIRES (with J. Chang), July 14, 2017.

How Wholesale Power Markets and State Environmental Policies Can Work Together, Published in Utility Dive (with S. Newell, J. Chang, and K. Spees), July 10, 2017.

Advancing Past "Baseload" to a Flexible Grid: How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix, Prepared for NRDC

(with J. Chang, M. Geronimo Aydin, and others), June 26, 2017; Presented to the Senate Energy & Natural Resources Committee on July 28, 2017.

Reforming Ontario's Wholesale Electricity Market: The Costs and Benefits, Published in Energy Regulation Quarterly (with K. Spess, J. Chang, and others), Volume 5, Issue 2, June 2017.

The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project, Prepared for IESO (with K. Spees, J. Chang and others), April 20, 2017.

Western Regional Market Developments: Impact on Renewable Generation Investments and Balancing Costs, Presented at the Wind Power Finance & Investment Summit (with O. Aydin and J. Chang), February 7, 2017.

The Role of RTO/ISO Markets in Facilitating Renewable Generation Development, The Brattle Group (with J. Chang, O. Aydin, and D.L. Oates), December 8, 2016.

Electricity Market Restructuring: Where Are We Now?, National Council of State Legislators' Energy Policy Forum, December 6, 2016.

Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, Prepared for Basin Electric Power Cooperative, Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Cooperative, and Western Area Power Administration (with J. Chang and J. Tsoukalis), December 1, 2016.

Western Regional Market Developments: Impact on Renewable Generation Investments and Balancing Costs, Presented at the 9th Annual Large Solar Conference (with J. Chang), October 19, 2016.

The Future for Competitive Transmission: What Have We Learned and Where Do We Go From Here? Energy Bar Association's (EBA) 2016 Mid-Year Energy Forum (with J. Chang), October 6, 2016.

Improved Transmission Planning for a Carbon-Constrained Future, BRINK, (with J. Chang and O. Aydin), September 1, 2016.

Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for CAISO (with J. Chang and others), July 8, 2016.

Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future, prepared for WIRES (with J. Chang), June 2016.

Open Letter to GAO: Response to U.S. Senators' Capacity Market Questions, Sent to the U.S. Government Accountability Office (GAO) (with S. Newell, K. Spees and R Lueken), May 5, 2016.

PJM Capacity Auction Results and Market Fundamentals, Prepared for the Bloomberg Analyst Briefing (with S. Newell and D.L. Oates), September 18, 2015.

Transmission: A Valuable Investment for New England's Energy Future, Presented at the New England Energy Policy Discussion, Boston, MA (with J. Chang), July 23, 2015.

Investment Trends and Fundamentals in U.S. Transmission and Electricity Infrastructure, Presented to the JP Morgan Investor Conference (with J. Chang and J. Tsoukalis), July 17, 2015.

Hidden Values, Missing Markets, and Electricity Policy: The Experience with Storage and Transmission, Harvard Electricity Policy Group, (with J. Chang), June 25, 2015.

Impacts of Distributed Storage on Electricity Markets, Utility Operations, and Customers, MIT Energy Initiative Symposium (with J. Chang, K. Spees, and M. Davis), May 1, 2015.

Transmission As a Market Enabler: The Costs and Risks of an Insufficiently Flexible Electricity Grid, WIRES University, Washington, DC (with J. Chang), April 21, 2015.

Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, prepared for WIRES (with J. Chang and A. Sheilendranath), April 2015.

Emerging Business Models for Non-Incumbent Transmission Projects, 18th Annual INFOCAST Transmission Summit 2015, Washington, DC, March 12, 2015.

The Value of Distributed Electricity Storage in Texas—Proposed Policy for Enabling Grid-Integrated Storage Investments (Full Technical Report), (with J. Chang, K. Spees, M. Davis, and others), prepared for Oncor, March 2015.

The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments, (with J. Chang, K. Spees, and M. Davis), Energy Storage Policy Forum 2015, Washington, DC, January 29, 2015.

Nebraska Renewable Energy Exports: Challenges and Opportunities, (with J. Chang, M. Hagerty, and A. Murray), prepared for the Nebraska Power Review Board, December 12, 2014.

Dynamics and Opportunities in Transmission Development, (with J. Chang and J. Tsoukalis), TransForum East, Washington, DC, December 2, 2014.

The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments (with J. Chang, K. Spees, M. Davis, I. Karkatsouli, L. Regan, and J. Marshal), prepared for Oncor, November 2014.

Resource Adequacy Requirements, Scarcity Pricing, and Electricity Market Design Implications*, presented at the IEA Electricity Security Advisory Panel (ESAP), Paris, France, July 2, 2014.*

Third Triennial Review of PJM's Variable Resource Requirement Curve (with S. Newell, K. Spees, and *others), capacity market design review prepared for PJM, May 15, 2014.*

Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM: with June *1, 2018 Online Date (with K. Spees, S. Newell, J.M. Hagerty, and others), prepared for PJM, May 15, 2014.*

Contrasting Competitively-Bid Transmission Investments in the U.S. and Abroad, UBS Conference *Call webinar, May 13, 2014 (with J. Chang, M. Davis, and M. Geronimo).*

Transmission to Capture Geographic Diversity of Renewables: Cost Savings Associated with Interconnecting *Systems with High Renewables Penetration* (with J. Chang, P. Ruiz, and K Van Horn), Presented to TransForum West, San Diego, CA, May 6, 2014.

Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks (prepared with S. Newell and K. Spees), Presented at the Harvard Electricity Policy Group Seventy-Fourth Plenary Session, February 27, 2014.

Market-Based Approaches to Resource Adequacy, prepared for IESO Stakeholder Summit, Toronto, Ontario, Canada, February 11, 2014.

Competition in Transmission Planning and Development: Current Status and International Experience (with Judy Chang, Matthew K. Davis, and Mariko Geronimo), prepared for the EUCI's Transmission Policy: A National Summit, Washington, DC, January 31, 2014.

Estimating the Economically Optimal Reserve Margin in ERCOT (with S. Newell, K. Spees, I. Karkatsouli, N. Wintermantel, and K. Carden), prepared for The Public Utility Commission of Texas, January 31, 2014.

"Using Virtual Bids to Manipulate the Value of Financial Transmission Rights" (with S. Ledgerwood), *The Electricity Journal*, Vol. 26, Issue 9, November 2013.

"Characteristics of Successful Capacity Markets" (with K. Spees), *APEx Conference*, New York, NY, October 31, 2013.

Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process (with J. Chang, S. Newell, B. Tsuchida and M. Hagerty), prepared for ERCOT, October 2013.

Resource Adequacy Requirements: Reliability and Economic Implications (with K. Spees, K. Carden, and N. Wintermantel), prepared for the Federal Energy Regulatory Commission (FERC), September 2013.

"Capacity Markets: Lessons Learned from the First Decade" (with K. Spees and S. Newell), *Economics of Energy & Environmental Policy*, Vol. 2, No. 2, Fall 2013.

"Trends and Benefits of Transmission Investments: Identifying and Analyzing Value" (with J. Chang and M. Hagerty), presented to the *CEA Transmission Council*, Ottawa, Canada, September 26, 2013.

"Examining Hydroelectricity's Potential Role in the Alberta Market: Impacts of Market Structure and Economics," *Alberta Power Symposium*, Calgary, September 24, 2013.

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments (with J. Chang and M. Hagerty), prepared for WIRES, July 2013.

"Making Energy-Only Markets Work: Market Fundamentals and Resource Adequacy in Alberta," presented at the Harvard Electricity Policy Group meeting, June 13, 2013.

"Independent Transmission Companies: Business Models, Opportunities, and Challenges," presented at the American Antitrust Institute's 13th Annual Energy Roundtable, Washington, DC, April 23, 2013.

"Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update" (with K. Spees and M. DeLucia), prepared for the Alberta Electric System Operator, March 2013.

"Structural Challenges with California's Current Forward Procurement Construct," presented at the *CPUC and CAISO Long-Term Resource Adequacy Summit*, February 26, 2013.

"Bridging the Seams: Interregional Planning Under FERC Order 1000" (with J. Chang and D. Hou), *Public Utilities Fortnightly*, November 2012.

"Interregional Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," presented to the Harvard Electricity Policy Group, October 11, 2012.

"Resource Adequacy in California: Options for Improving Efficiency and Effectiveness" (with K. Spees and S. Newell), prepared for Calpine, October 2012.

"Resource Adequacy Designs in U.S. Power Markets: PJM," presented at the Gulf Coast Power Association 27th Annual Fall Conference, Austin, TX, October 1, 2012.

"Resource Adequacy in International Power Markets and Alberta," presented at the Gulf Coast Power Association 27th Annual Fall Conference, Austin, TX, October 1, 2012.

"Resource Adequacy and Capacity Markets: Overview, Trends, and Policy Questions," presented at New England Electricity Restructuring Roundtable, Boston, MA, September 21, 2012.

"Transmission Investment Trends and Planning Challenges," presented at the EEI Transmission and Wholesale Markets School, Madison, WI, August 8, 2012.

"Seams Inefficiencies: Problems and Solutions at Energy Market Borders" (with K. Spees), presented at the EUCI Canadian Transmission Summit, July 17, 2012.

"The Benefits of Transmission Expansion," presented at the EUCI Canadian Transmission Summit, July 17, 2012.

"The Economics of Reliability and Resource Adequacy Planning," presented at the Mid-America Regulatory Conference, Des Moines, IA, June 12, 2012.

"ERCOT Investment Incentives and Resource Adequacy" (with S. A. Newell, K. Spees, R. S. Mudge, M. DeLucia, and R. Carlton), prepared for the Electric Reliability Council of Texas, June 1, 2012.

"Resource Adequacy," presented at the IRC Board Conference, Dallas, TX, May 23, 2012.

"Review of EIPC's Phase 1 Report" (with P.S. Fox-Penner, and D. Hou), prepared for the Working Group for Investment in Reliable and Economic Electric Systems (WIRES), May 22, 2012.

"Using Virtual Bids to Manipulate the Value of Financial Transmission Rights" (with by S.D. Ledgerwood), SSRN Working Paper Series, May 3, 2012.

Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning (with D. Hou), prepared for the Southwest Power Pool Regional State Committee, April 2012.

"Transmission's True Value: Adding Up the Benefits of Infrastructure Investments" (with D. Hou), *Public Utilities Fortnightly*, February 2012.

Update on RSC Seams Cost Allocation Effort (with D. Hou), Presented to FERC Staff, February 7, 2012.

Modernizing America's Grid: How can better planning deliver the grid we need? New England Clean Energy Transmission Summit, Boston, MA, January 23, 2012.

"Trusting Capacity Markets: Does the Lack of Long-term Pricing Undermine the Financing of New Power Plants?" (with S. Newell), *Public Utilities Fortnightly*, December 2011.

Reliability and Economics: Separate Realities or Part of the Same Continuum? Harvard Electricity Policy Group, December 1, 2011.

Resource Adequacy: Current Issues in North American Power Markets (with K. Spees), Alberta Power Summit, November 29, 2011.

Recent FERC Actions and Implications for Transmission in the West, EUCI Western Transmission Conference: Connecting Renewables to the Grid in the Southwest, Scottsdale, Arizona, October 25, 2011.

Summary of Transmission Project Cost Control Mechanisms in Selected U.S. Power Markets (with D. Hou), prepared for the Alberta Electric System Operator, October 2011.

Transmission Cost Allocation and Cost Recovery in the West, Transmission Executive Forum West 2011 – Strategies for Meeting the Transmission Needs in the West, San Francisco, September 19, 2011.

Resource Adequacy: More than just keeping the lights on (with K. Carden), NRRI Teleseminar, September 15, 2011.

Second Performance Assessment of PJM's Reliability Pricing Model (with S.A. Newell, K. Spees, A. Hajos, and K. Madjarov), August 26, 2011.

Cost of New Entry Estimates For Combustion-Turbine and Combined-Cycle Plants in PJM (with K. Spees, S. A. Newell, R. Carlton, and B. Zhou), August 24, 2011.

"Restructuring Realities: Can higher electricity prices be more affordable?" (with A.C. Schumacher), *Public Utilities Fortnightly*, July 2011.

Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada (with D. Hou), Report prepared for WIRES, May 2011.

U.S. Transmission Needs and Planning Challenges, EEI Transmission Policy Task Force, May 5, 2011.

Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market (with K. Spees), Report prepared for the Alberta Electric System Operator, April 2011.

Barriers to Transmission Investments and Implications for Competition in Wholesale Power Markets, The American Antitrust Institute, April 12, 2011.

The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On (with K. Carden and N. Wintermantel), NRRI Report 11-09, April 2011.

"The Value of Resource Adequacy: Why Reserve Margins Aren't Just About Keeping the Lights On" (with K. Carden and N. Wintermantel), *Public Utilities Fortnightly*, March 2011.

Demand Response Review (with A. Hajos), Report prepared for Alberta Electric System Operator, March 2011.

Easier Said Than Done: The Continuing Saga of Transmission Cost Allocation, Harvard Electricity Policy Group meeting, Los Angeles, February 24, 2011.

"Executive Summary – An Assessment of the Public Policy, Reliability, Congestion Relief, and Economic Benefits of the Atlantic Wind Connection" (with S. Newell), December 21, 2010.

Transmission Investments and Cost Allocation: What are the Options? ELCON Fall Workshop, October 26, 2010.

Transmission Planning: Economic vs. Reliability Projects, EUCI Conference, Chicago, October 13, 2010.

"Renewable Energy Development and Transmission Expansion – Who Benefits and Who Pays," October 12, 2010.

Resource Adequacy and Renewable Energy in Competitive Wholesale Electricity Markets (with S. Hesmondhalgh and D. Robinson), article presented at the 8th British Institute of Energy Economics (BIEE) Academic Conference, Oxford, September 2010.

Transmission Planning and Cost Benefit Analysis (with D. Hou), EUCI Web Conference, September 22, 2010.

"Transmission Planning: Overarching Challenges to Regional Expansion," *Electric Transmission 203: Planning to Expand and Upgrade the Grid*, WIRES and EESI Senate Staff Briefing Series, June 28, 2010.

Potential Carbon Emission Reductions and Costs of Delivering Wind Energy from the Plains & Eastern Clean Line Transmission Project (with J. Weiss and D. Hou), report prepared for Cleanline Energy Partners, June 2010.

"For Grid Expansion, Think 'Subregionally'" (with P. Fox-Penner and D. Hou), *Energy Daily*, June 8, 2010.

"Incentive Regulation: Lessons from other Jurisdictions" (with T. Brown and P. Carpenter), Alberta Utilities Commission workshop, Edmonton, May 27, 2010.

"Incentive Regulation: Introduction and Context," Alberta Utilities Commission workshop, Edmonton, May 26, 2010.

Job and Economic Benefits of Transmission and Wind Generation Investments in the SPP Region (with J. Chang, D. Hou, and K. Madjarov), Report prepared for Southwest Power Pool, March 2010.

Challenges to Alberta's Energy-Only Market Structure?, IPPSA 16th Annual Conference, Banff Springs, Alberta, March 15, 2010.

Best Practices in Resource Adequacy, presented at the PJM Long Term Capacity Issues Symposium (with K. Spees), January 27, 2010.

"Transmission Investment Needs and Cost Allocation: New Challenges and Models" (with P.S. Fox-Penner and D. Hou), December 1, 2009.

A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs (with K. Spees and A. Schumacher), Report prepared for PJM Interconnection LLC, September 2009.

Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation (with K. Belcher, J. Chang, and D. Hou), Report prepared for Central Maine Power Company and the Industrial Energy Consumer Group, May 2009.

Review of PJM's Reliability Pricing Model (RPM) (with S. Newell, R. Earle, A. Hajos, and M. Geronimo), Report prepared for PJM Interconnection LLC, June 30, 2008.

"Assessing the Benefits of Transmission Investments," Working Group for Investment in Reliable and Economic Electric Systems (WIRES) meeting, Washington, DC, February 14, 2008.

"The Power of Five Percent" (with A. Faruqui, R. Hledik, and S. Newell), *The Electricity Journal*, October 2007.

Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets (with J. Reitzes, P. Fox-Penner and others), Report prepared for PJM Interconnection LLC, September 14, 2007.

"Restructuring Revisited: What We Can Learn from Retail Rate Increases in Restructured and Non-Restructured States" (with G. Basheda and A. Schumacher), *Public Utilities Fortnightly*, June 2007.

"The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs" (with A. Faruqui, R. Hledik, and S. Newell), Discussion Paper, *The Brattle Group*, May 16, 2007.

"Evaluating the Economic Benefits of Transmission Investments" (with S. Newell), EUCI Conference, Nashville, Tennessee, May 3, 2007.

"Valuing Demand-Response Benefits in Eastern PJM" (with S. Newell and F. Felder), *Public Utilities Fortnightly*, March 2007.

"Financial Challenges of Rising Utility Costs and Capital Investment Needs" (with A. Schumacher), 2006 NASUCA Annual Meeting, Miami, Florida, November 14, 2006.

"Financial Pressures Ahead: Can Utilities Simultaneously Manage Rising Costs and Pressing Capital Investment Needs?," *Public Utilities Fortnightly*, October 2006.

"Behind the Rise in Prices: Electricity Price Increases are Occurring Across the Country, Among all Types of Electricity Providers – Why?" (with G. Basheda, M. Chupka, P. Fox-Penner, and A. Schumacher), *Electric Perspectives*, July/August 2006.

"Why Are Electricity Prices Increasing: An Industry-Wide Perspective" (with G. Basheda, M. Chupka, P. Fox-Penner, and A. Schumacher), prepared for The Edison Foundation, June 2006.

"Understanding Utility Cost Drivers and Challenges Ahead" (with A. Schumacher), *AESP Pricing Conference*, Chicago, May 17, 2006.

"Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models" (with S. Newell), *Energy*, Vol 2, 2006.

"When Sparks Fly: Economic Issues in Complex Energy Contract Litigation" (with D. Murphy and G. Taylor), *Energy*, Vol 1, 2006.

Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry (with S. Newell), Newsletter of the American Bar Association, Section on Environment, Energy, and Resources, pp. 3-6, October 2005.

"Keeping Up with Retail Access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service" (with J. Wharton and A. Schumacher), *The Electricity Journal*, December 2004.

Can Utilities Play on the Street? Issues in ROE and Capital Structure, opening comments for panel discussion on "Traditional and Alternative Methods for Determining Return on Investment," Financial Research Institute Conference, Columbia, Missouri, September 16, 2004.

"What is Reasonable? How to Benchmark Return on Equity (ROE) and Depreciation Expense in Utility Rate Cases" (with M.Jenkins), *Public Utilities Fortnightly*, October 15, 2003.

"Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates" (with D. Weisman), *The Electricity Journal*, January/February 2003.

"Big City Bias: The Problem with Simple Rate Comparisons" (with M. Jenkins), *Public Utilities Fortnightly*, December 2002.

Power Market Design in Europe: The Experience in the U.K. and Scandinavia (with C. Lapuerta), Energy Bar Association, 56th Annual Meeting, Washington, DC, April 18, 2002.

"REx Incentives: PBR Choices that Reflect Firms' Performance Expectations" (with P. Carpenter and P. Liu), *The Electricity Journal*, November 2001.

"The State of Performance-Based Regulation in the U.S. Electric Utility Industry" (with D. Sappington, P. Hanser and G. Basheda), *The Electricity Journal*, October 2001.

"Eine wettbewerbliche Analyse beabsichtigter Zusammenschluesse in der Deutschen Elektrizitaetswirtschaft" (A Competitive Analysis of Proposed Mergers in the German Power Industry)," presentations to the German Cartel Office and the Merger Task Force of the European Commissions, February 2000.

"Transmission Access, Episode II: FERC's Journey Has Only Begun" (with P. Fox-Penner), *Public Utilities Fortnightly*, August 1999.

"Netzzugang in Deutschland im internationalen Vergleich" (International Benchmarking of German Transmission Access) (with C. Lapuerta, W. Pfaffenberger, and J. Weiss), *Energiewirtschaftliche Tagesfragen*, July 1999.

"Netzzugang in Deutschland – ein Ländervergleich" (Transmission Access in Germany – an International Comparison) (with C. Lapuerta and W. Pfaffenberger), *Wirtschaftswelt Energie*, March 1999, pp. 9-11 (Part I) and April 1999, pp. 12-14 (Part II).

Transmission Access In Germany Compared to Other Transmission Markets (with C. Lapuerta and W. Pfaffenberger), commissioned by Enron Europe Ltd., December 1998, updated February 1999.

"Competition to International Satellite Communications Services" (with H. Houthakker), *Information Economics and Policy*, Vol. 10 (1998) 403-430.

"In What Shape is Your ISO" (with P. Hanser, G. Basheda, and P. Fox-Penner), *The Electricity Journal*, July 1998.

Distributed Generation: Threats and Opportunities (with P. Hanser and D. Chodorow), Electric Distribution Conference, Denver Colorado, April 28-29, 1998.

What's in the Cards for Regulated Distribution Companies (with P. Hanser and D. Chodorow), Electric Distribution Conference, Denver Colorado, April 28-29, 1998.

Does Generation Divestiture Mitigate Market Power, 1998 Energy Futures Forum, Woodbridge, NJ, April 23, 1998.

Joint Response to the Satellite Users' Coalition "Analysis of the Privatization of the Intergovernmental Satellite Organizations as Proposed in H.R. 1872 and S. 1382" (with H. Houthakker, M. Schwartz, W. Tye, and A. Maniatis), March 9, 1998.

"What's in the Cards for Distributed Resources?" (with P. Ammann and P. Hanser), *The Energy Journal*, Special Issue, January 1998.

An Economic Assessment of H.R. 1872 (analyzing the impact of a bill attempting to restructure the international satellite organizations) (with H. Houthakker and A. Maniatis), September 26, 1997.

"Considerations in the Design of ISO and Power Exchange Protocols: Procurement Bidding and Market Rules" (with F. Graves), *Electric Utility Consultants Bulk Power Markets Conference*, Vail, Colorado, June 4, 1997.

"The Top 10 'Other' Challenges to Success in Utility Mergers" (with W. Tye), *1997 Energy Futures Forum*, NJAEE, Woodbridge, New Jersey, April 17, 1997.

"Introduction to Market Power Concerns in a Restructured Electric Industry" (with others) *Brattle Presentation*, July 1996.

"Does Intelsat Face Effective Competition" (with H. Houthakker), Columbia Institute for Tele-Information, Conference, April 26, 1996.

"Distributed Generation Technology in a Newly Competitive Electric Power Industry" (with P. Ammann and G. Taylor), *American Power Conference*, Chicago, April 10, 1996.

"Handle with Care: A Primer on Incentive Regulation" (with W. Tye), *Energy Policy*, Vol 13, No. 8, September 1995.

"Measuring Property Value Impacts of Hazardous Waste Sites" (with K. Wise), Air & Waste Management Association, 88th Annual Meeting, June 18-23, 1995.

"The Not-So-Strange Economics of Stranded Investments" (with W. Tye), *The Electricity Journal*, Reply, November 1994.

"Purchased Power: Hidden Costs or Benefits?" (with S. Johnson, L. Kolbe, and D. Weinstein), *The Electricity Journal*, September 1994.

"Pricing Transmission and Power in the Era of Retail Competition" (with F. Graves), Electric Utility Consultants: Retail Wheeling Conference, June 1994.

"The Enigma of Stigma: The Case of the Industrial Excess Landfill" (with K. Wise), *Toxics Law Reporter*, Bureau of National Affairs, May 18, 1994.

"Banking on NUG Reliability: Do Leveraged Capital Structures Threaten Reliability?" (with S. Johnson and L. Kolbe) *Public Utilities Fortnightly*, May 15, 1994.

"Valuation and Renegotiation of Purchased Power Contracts" (with others), *The Brattle Group Presentation*, May 2, 1994.

"Still More on Purchased Power" (with S. Johnson), *The Electricity Journal*, Reply, February 1994.

"Purchased Power Risks and Rewards" (with A.L. Kolbe and S. Johnson), Presentation at the AGA/EEI Budgeting and Financial Forecasting Committee Meeting, February 28, 1994,

"Evaluation of Demand-Side Management Programs" (with others), *Capital Budgeting Notebook*, Electric Power Research Institute, Chapter 12, 1994.

"Purchased Power Risks and Rewards" (with S. Johnson and A.L. Kolbe), Report for the *Edison Electric Institute*, Fall 1993.

"Purchased Power Incentives" (with S. Johnson), *The Electricity Journal*, Reply, November, 1993.

"It's Time For A Market-based Approach to Demand-side Management" (with A.L. Kolbe), PowerGen '93 Conference, November 1993.

"Incentive Regulation: Dos and Don'ts" (with W. Tye), Electric Utility Consultants: Strategic Utility Planning Conference, June 1993.

"It's Time For A Market-based Approach to DSM" (with A.L. Kolbe, A. Maniatis, and D. Weinstein), *The Electricity Journal*, May, 1993.

"Charge It—Financing DSM Programs" (with D. Weinstein), *Public Utilities Fortnightly*, May 1, 1993.

"Fuel Switching and Demand-side Management" (with D. Weinstein) *Public Utilities Fortnightly*, May 1, 1992.

Development of Sectoral Energy Requirements in the Japanese Economy: 1970 to 1980, Master's Project in International Economics, Brandeis University, May 1991.

"The Costs of Hydropower: Evidence on Learning-by-Doing, Economies of Scale, and Resource Constraints in Austria" (with F. Wirl), *International Journal of Energy Research*, Vol. 14, pp. 893-899, 1990.

"Eine ökonomische Analyse alternativer Kraftwerkstypen" (an economic analysis of power supply alternatives) (with F. Wirl), *Girozentrale Quartalshefte*, pp. 21-30, January 1990.

"Eine einfache Charakterisierung der saisonalen Elektrizitätsnachfrage" (a simple characterization of seasonal electricity demand), *Österreichische Zeitschrift für Elektrizitätswirtschaft*, March 1990.

Kraftwerksausbauplanung mit Linearen Optimierungsmodellen am Beispiel Österreichs (power systems expansion planning for Austria with mixed-integer and linear-programming models), Master's Thesis, Institute of Energy Economics, University of Technology, Vienna, May 1989.

ATTACHMENT B: QUALIFICATIONS OF JOHN MICHAEL HAGERTY

John Michael Hagerty is a Principal of *The Brattle Group* in Washington, D.C. with thirteen years of work experience in transmission planning, electric power markets, utility regulation, and energy policy. He received a M.S. in Technology and Policy from the Massachusetts Institute of Technology in Cambridge, Massachusetts and a B.S. in Chemical Engineering from the University of Notre Dame in South Bend, Indiana. Prior to joining *The Brattle Group* in 2012, Mr. Hagerty was a research assistant at the MIT Energy Initiative in Cambridge, Massachusetts, a chemical process engineer at UOP/Honeywell in Des Plaines, Illinois, and a research chemist at GE Global Research in Niskayuna, New York.

TESTIMONY AND REGULATORY FILINGS

Before the Public Service Commission of Wisconsin, Docket 1515-CE-103, *Direct Testimony of John Michael Hagerty in Support of the Application*, regarding the Application of Dairyland Power Cooperative for a Certificate of Public Convenience and Necessity to Construct and Operate the Wisconsin Portion of Long Range Transmission Project Tranche 1 Project 4, Consisting of a New 345 kV Transmission Line in the Counties of Buffalo and Trempealeau, Wisconsin, also Known as the Alma to Blair Transmission Line Project, August 11, 2025.

Before the Federal Energy Regulatory Commission, Docket ER25-2707-000, *Prepared Direct Testimony and Exhibits of John Michael Hagerty on behalf of Viridon Path 15 LLC*, regarding Viridon Revised Appendix I in Path 15 Tariff Reflecting Updated TRR, June 30, 2025.

Before the Public Service Commission of Wisconsin, Docket 1515-CE-103, *MISO LRTP Tranche 1 Project 4 Benefit-Cost Analysis: Technical Report*, (with O. Kuzura, et al.), regarding the Application of Dairyland Power Cooperative for a Certificate of Public Convenience and Necessity to Construct and Operate the Wisconsin Portion of Long Range Transmission Project Tranche 1 Project 4, Consisting of a New 345 kV Transmission Line in the Counties of Buffalo and Trempealeau, Wisconsin, also Known as the Alma to Blair Transmission Line Project, June 2, 2025.

Before the Federal Energy Regulatory Commission, Docket ER25-1674, *MISO Resource Adequacy Needs and Impacts of the Proposed ERAS Process*, (with C. Shen and E. Bennett), prepared for NextEra Energy Resources, Inc., April 7, 2025.

Before the Public Service Commission of Wisconsin, Docket 6630-CE-317, *Oral Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding the Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek CT Project, Consisting of Five Natural Gas-Fired Single-Cycle Combustion Turbines Generating up to 1100 MW total at the South Oak Creek Facility in the City of Oak Creek, Milwaukee County, Wisconsin, March 12, 2025.

Before the Public Service Commission of Wisconsin, Docket 6630-CE-317, *Rebuttal Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding the Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek CT Project, Consisting of Five Natural Gas-Fired Single-Cycle Combustion Turbines Generating up to 1100 MW total at the South Oak Creek Facility in the City of Oak Creek, Milwaukee County, Wisconsin, February 18, 2025.

Before the Public Service Commission of Wisconsin, Docket 6630-CE-316, *Oral Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding the Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project, Consisting of Seven Natural Gas-Fired Reciprocating Internal Combustion Engines Generating up to 128 MW Total at the Lakeshore Capacity Improvement Project Regulator Station in the Town of Paris, Kenosha County, Wisconsin, February 13, 2025.

Before the Public Service Commission of Wisconsin, Docket 6630-CE-316, *Rebuttal Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding the Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project, Consisting of Seven Natural Gas-Fired Reciprocating Internal Combustion Engines Generating up to 128 MW Total at the Lakeshore Capacity Improvement Project Regulator Station in the Town of Paris, Kenosha County, Wisconsin, January 17, 2025.

Before the Public Service Commission of Wisconsin, Docket 6630-CG-140, *Direct Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding the Application of Wisconsin Electric Power Company for a Certificate of Authority under Wis. Stat § 196.49 and Wis. Admin. Code § PSC 133.03 to Construct a New Liquified Natural Gas Facility and Associated Natural Gas Pipelines in Oak Creek, Wisconsin, December 12, 2024.

Before the Public Service Commission of Wisconsin, Docket 6630-CE-317, *Direct Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding the Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek CT Project, Consisting of Five Natural Gas-Fired Single-Cycle Combustion Turbines Generating up to 1100 MW total at the South Oak Creek Facility in the City of Oak Creek, Milwaukee County, Wisconsin, November 20, 2024.

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-316, *Direct Testimony of John Michael Hagerty on behalf of Wisconsin Electric Power Company*, regarding Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project, Consisting of Seven Natural Gas-Fired Reciprocating Internal Combustion Engines Generating up to 128 MW Total at the Lakeshore Capacity Improvement Project Regulator Station in the Town of Paris, Kenosha County, Wisconsin, October 2024.

Before the Federal Energy Regulatory Commission, Docket No. AD24-9-000, *Pre-Workshop Comments of John Michael Hagerty*, Staff-Led Workshop on Innovations and Efficiencies in Generator Interconnection, September 8, 2024.

Before the South Carolina Public Service Commission, Docket No. 2023-8-E/2023-10-E, *Direct Testimony of John Michael Hagerty on behalf of Carolinas Clean Energy Business Association,* in the matters of Duke Energy Progress, LLC's 2023 Integrated Resource Plan (IRP) and Duke Energy Carolinas, LLC's 2023 Integrated Resource Plan (IRP), July 1, 2024.

Before the North Carolina Utilities Commission, Docket No. E-100, Sub 190, *Direct Testimony of John Michael Hagerty on behalf of Carolinas Clean Energy Business Association*, in the matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and§ 62-110.l(c), May 28, 2024.

Before the North Carolina Utilities Commission, Docket No. E-100, Sub 179, *Oral Testimony of John Michael Hagerty on behalf of Clean Power Suppliers Association*, in the matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan, September 26, 2022.

Before the North Carolina Utilities Commission, Docket No. E-100, Sub 179, *Direct Testimony of John Michael Hagerty on behalf of Clean Power Suppliers Association*, in the matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan, September 2, 2022.

Before the Public Service Commission of Wisconsin, Docket No. 5-CE-153, *Oral Testimony of John Michael Hagerty on behalf of Wisconsin Public Service Corporation and Wisconsin Electric Power Company*, regarding Joint Application of Wisconsin Public Service Corporation and Wisconsin Electric Power Company for Authority to Construct the Weston Reciprocating Internal Combustion Engine Project in the Villages of Rothschild and Kronenwetter, Marathon County, Wisconsin, January 2022.

Before the Public Service Commission of Wisconsin, Docket No. 5-BS-254, *Rebuttal Testimony of John Michael Hagerty*, prepared for Wisconsin Electric Power Company and Wisconsin Public Service Corporation, regarding Joint Application of Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Madison Gas and Docket Electric Company for Approval to Acquire Ownership Interests in the Paris Solar Generating and Battery Energy Storage System, December 2021.

Before the Public Service Commission of Wisconsin, Docket No. 5-CE-153, *Direct Testimony of John Michael Hagerty on behalf of Wisconsin Public Service Corporation and Wisconsin Electric Power Company*, regarding Joint Application of Wisconsin Public Service Corporation and Wisconsin Electric Power Company for Authority to Construct the Weston Reciprocating Internal Combustion Engine Project in the Villages of Rothschild and Kronenwetter, Marathon County, Wisconsin, September 2021.

Before the Public Service Commission of the District of Columbia, Formal Case No. 1167, *An Assessment of Electrification Impacts on the Pepco DC System*, (with R. Hledik, S. Sergici, and J. Olszewski), prepared for Pepco Holdings, Inc., August 27, 2021.

Before the Federal Energy Regulatory Commission, Docket No. ER21-424, *Prepared Direct Testimony of Dr. Jurgen Weiss and John M. Hagerty,* November 12, 2020. Attachment A to *Application for Authorization to Recovery Costs Associated with an Electric Vehicle Infrastructure Pilot Project*, November 12, 2020.

Before the Federal Energy Regulatory Commission, Docket No. ER20-2308, *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty* on behalf of LS Power, *re:* Comments in Support of PJM Stakeholder Approved Section 205 Filing (for treatment of End of Life Projects), July 23, 2020.

Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), *Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* June 1, 2020. Attachment D to *Second Compliance Filing concerning Application of the Minimum Offer Price Rule*, June 1, 2020.

Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), *Supplemental Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* March 25, 2020. Attachment to *Re: PJM Interconnection, L.L.C., Docket Nos. EL16-49, EL18-178, ER18-1314 Errata to PJM Compliance Filing re: Hope Creek Nuclear Plant*, March 25, 2020.

Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), *Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* March 18, 2020. Attachment D to *Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for an Extended Comment Period of at least 35 Days*, March 18, 2020.

Before the Public Utilities Commission of California, Application 16-10-12, *Ten West Link Economic and Public Policy Benefits and Costs Analysis, Technical Report*, (with J. Chang., J. Pfeifenberger, M. Tracy, and J.I. Pedtke), prepared for DCR Transmission LLC, December 20, 2019.

Before the Alberta Utilities Commission, Proceeding #23757, Oral Testimony on behalf of the Alberta Electric System Operator re: Alberta Electric System Operator Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, April 30 to May 3, 2019.

Before the Alberta Utilities Commission, Proceeding #23757, *Demand Curve and Energy and Ancillary Services Offset: Response to Intervener Evidence in Alberta Utilities Commission Proceeding #23757*, prepared by Kathleen Spees, J. Michael Hagerty, Cathy Wang, and Matthew Witkin, April 11, 2019, Appendix "A" to *Rebuttal Evidence of the Alberta Electric System Operator,* April 12, 2019.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Answering Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM*

Interconnection, L.L.C regarding Cost of New Entry Parameters, December 14, 2018, Attachment A to *Answer of PJM Interconnection, L.L.C. to Protests and Comments*, December 17, 2018.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* November 5, 2014. Attachment E to *Re: Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters*, November 6, 2014.

ARTICLES, REPORTS AND PRESENTATIONS

Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy, (with P. Heller and E. Bennett), prepared for Carolinas Clean Energy Business Association, Clean Energy Buyers Association, and Southern Renewable Energy Association, April 2, 2025.

Proposal to Develop Optimal Transmission Planning in Alberta, (with J. Pfeifenberger, et al.), prepared for Alberta Electricity System Operator, March 2025.

Southeast Regional Transmission Needs and Planning Improvements, (with P. Heller and E. Bennett), presented to SERTP Order 1920 Stakeholder Engagement Meeting, prepared for Clean Grid Initiative, January 29, 2025.

Maine Pathways to 2040: Insights and Analysis, (with D. Murphy, et al.), prepared for Maine Governor's Energy Office, January 2025.

Southern Renewable Energy Association Comments on Tennessee Valley Authority's Draft 2025 Integrated Resource Plan, (with J. Tsoukalis, et al.), prepared for Southern Renewable Energy Association, December 11, 2024.

Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid, (with R. Gramlich, et al.), presented to NEPOOL Transmission Committee, December 2024.

Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid, (with R. Gramlich, et al.), prepared for Advanced Energy Institute, Solar and Storage Industries Institute, and Clean Energy Buyers Association, August 2024.

Grid Needs to Support EV Charging and Other Load Growth, presented to LSI Electric Vehicle Charging Infrastructure Conference, June 20, 2024.

Value of Solar in IRP Portfolios and Need for Proactive Transmission Planning, presented to NCUC Carolinas Resource Plan Technical Conference, June 17, 2024.

Thermal Batteries and Industrial Decarbonization Load Growth, presented to ESIG 2024 Forecasting & Markets Workshop, June 12, 2024.

Generator Interconnection Scorecard: Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators, (with J. Wilson, et al.), prepared for Advanced Energy United, February 2024.

An Assessment of Electrification Impacts on the Maryland Electric Grid, (with S. Sergici, et al.), prepared for Maryland Public Service Commission, December 19, 2023.

New England Energy Storage Duration Study, (with R. Sreenath, et al.), prepared for Cypress Creek Renewables, December 18, 2023.

Thermal Batteries: Opportunities to Accelerate Decarbonization of Industrial Heat, (with K. Spees, J. Grove), prepared for Center for Climate and Energy Solutions and Renewable Thermal Collaborative, October 2023.

MISO South Tranche 3 Transmission Planning and Cost Allocation, (with J. Tsoukalis), presented to Entergy Regional State Committee, September 2023.

TransCanyon, LLC Cross-Tie Independent Market Report, (with J. Tsoukalis, et al.), prepared for TransCanyon, LLC, July 2023.

Southwest Intertie Project—North Independent Market Report, (with J. Pfeifenberger, et al.), prepared for Great Basin Transmission, LLC, June 2023.

BGE School Bus Electrification Benefit-Cost Analysis, (with S. Sergici, et al.), prepared for Baltimore Gas & Electric, May 2023.

New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, (with J. Pfeifenberger, et al.), prepared for the New Jersey Board of Public Utilities, October 2022.

ERCOT EV Allocation Study: Methodology for Determining EV Load Impact at the Substation Level, (with S. Sergici, et al.), prepared for ERCOT, October 11, 2022.

Community Solar Value Stack in Arizona, (with S. Sergici, et al.), prepared for Cypress Creek Renewables, August 30, 2022.

Transportation Electrification Cost-Benefit Analysis for Public Service Company of Colorado, (with S. Sergici, et al.), prepared for Public Service Company of Colorado, May 2022.

PJM CONE 2026/2027 Report, (with S. Newell, et al.), prepared for PJM Interconnection, L.L.C., April 21, 2022.

Pepco's Climate Solutions 5-Year Action Plan: Benefits and Costs, (with R. Hledik, S. Sergici), prepared for Pepco Holdings, Inc., February 4, 2022.

A Roadmap to Improved Interregional Transmission Planning, (with J. Pfeifenberger, K. Spokas, J. Tsoukalis), prepared for Natural Resource Defense Council, November 30, 2021.

Designing Effective EV Managed Charging Programs, (with S. Sergici), presented at Peak Load Management Association (PLMA) webinar, October 28, 2021.

The Customer Action Pathway to National Decarbonization, (with S. Sergici, R. Hledik, K. Peters, and A. Faruqui), prepared for Oracle Utilities, October 21, 2021.

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, (with J. Pfeifenberger, K. Spokas, J. Tsoukalis), prepared for ACORE and Natural Resource Defense Council, October 13, 2021.

A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation, (with M. Celebi, M. Witkin, J. Olszewski, and F. Corpuz), prepared for Cypress Creek Renewables, August 31, 2021.

Target − Plan − Finance: A Framework for Climate Policy in Federal Infrastructure Legislation, A Discussion Draft, (with P. Fox-Penner, K. Spokas, G. Jones, A. Gutner-Davis, and R. Janakiraman), July 2021.

SWIP-North Benefits Analysis, (with J. Pfeifenberger and E. Bennett), prepared for Great Basin Transmission, February 2021.

The Road to 100% Renewable Electricity by 2030 in Rhode Island, (with D. Murphy and J. Weiss), prepared with Rhode Island Office of Energy Resources, January 13, 2021.

Electricity Transmission and Railroads: A Synergy of Needs and Right-of-Ways, (with J. Pfeifenberger), prepared for Rail Electrification Council, November 19, 2020.

Considerations for Meeting Sub-Annual Needs and Resource Accreditation across RTOs (with S. Newell, J. Pfeifenberger, and W. Graf), prepared for MISO Resource Adequacy Subcommittee, July 8, 2020.

Getting to 20 Million EVs by 2030: Opportunities for the Electricity Industry in Preparing for an EV Future, (with S. Sergici and L. Lam), June 2020.

Industry Changes in Resource Adequacy Requirements, Metrics, and Design Elements, (with S. Newell, J. Pfeifenberger, and W. Graf), prepared for MISO Resource Adequacy Subcommittee, May 6 and May 20, 2020.

Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency, (with Samuel A. Newell, Sanem Sergici, Jesse Cohen, Sang H. Gang, John Wroble, Patrick S. Daou), prepared for PJM Interconnection, March 17, 2020.

A New Paradigm for Utilities: Electrification of the Transportation and Heating Sectors, (with Ryan Hledik, Ahmad Faruqui, Jürgen Weiss, and Long Lam), published by the American Bar Association, November 13, 2019.

Achieving 80% GHG Reduction in New England by 2050: Why the Region Needs to Keep its Foot on the Clean Energy Accelerator, (with Jürgen Weis, Maria Castañer, and John Higham), prepared for the Coalition for Community Solar Access, September 25, 2019.

Response to Concentric Energy Advisors' Report on Competitive Transmission, prepared for LSP Transmission Holdings, LCC (with J. Chang, M. Hagerty, and J. Cohen), August 2019.

The Total Value Test: A Framework for Evaluating the Cost-Effectiveness of Efficient Electrification, (with Ryan Hledik, Ahmad Faruqui, and John Higham), Published by the Electric Power Research Institute (EPRI), August 2019.

Cost Saving Offered by Competition in Electric Transmission: Experience to Date and Potential Value for Electricity Customers, presented to Energy Bar Association (with J. Chang and J. Pfeifenberger), May 7, 2019.

Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, prepared for LSP Transmission Holdings, LLC (with J. Chang, J. Pfeifenberger, A. Sheilendranath, S. Levin, and W. Jiang), April 2019

Transmission in a Decarbonized and Electrified World, (with Jurgen Weiss and Maria Castaner), presented at Transmission and Clean Energy in the Northeast, March 26, 2019.

The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid, (with Jurgen Weiss and Maria Castaner), prepared for WIRES Group, March 2019.

The Role of Transmission in the Future Electric Power System, presented at WIRES University Transmission 101, February 25, 2019.

On the Path to Decarbonization: Can Electricity Markets Adapt to Meet Carbon Goals in the Western U.S.?, presented at Buying and Selling Electric Power in the West, January 23, 2019.

Seeking a Landing Point: Transmission Needs for U.S. Offshore Wind Generation, presented at AWEA Offshore WINDPOWER Conference, (with Johannes Pfeifenberger, Judy Chang, Akarsh Sheilendranath), October 16, 2018.

AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date, (with Johannes Pfeifenberger, Kathleen Spees, Mike Tolleth, Martha Caulkins, Emily Shorin, Sang Gang, Patrick Daou, and John Wroble), prepared for Alberta Electric System Operator, September 2018.

PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, (with Samuel Newell, Johannes Pfeifenberger, Bin Zhou, Emily Shorin, Perry Fitz, Sang Gang, Patrick Daou, and John Wroble), prepared for PJM Interconnection, April 2018.

Fourth Review of PJM's Variable Resource Requirement Curve, (with Samuel Newell, David Luke Oates, Johannes Pfeifenberger, Kathleen Spees, John Imon Pedtke, Matthew Witkin, and Emily Shorin), prepared for PJM Interconnection, April 2018.

Battery Storage Development: Regulatory and Market Environments, presented to Philadelphia Area Municipal Analyst Society, (with Judy Chang), January 2018.

Long-Term Implications of Negative Prices for West Coast Electricity Markets, presented at Buying & Selling Electric Power in the West, (with Johannes Pfeifenberger), January 2018.

The Future of Cap-and-Trade Program in California: Will Low GHG Prices Last Forever?, (with Yingxia Yang, Ashley Palmarozzo, Hannah Sheffield, Metin Celebi, Marc Chupka, and Frank C. Graves), December 2017.

Modelling Enhancements for CAISO Transmission Planning: The Feasibilty and Value of Incorporating Scheduling Constraints into CAISO's Planning Model, (with Judy Change, Johannes Pfeifenberger, Kai Van Horn, John Imon Pedtke, and Jesse Cohen), prepared for LS Power, October 2017.

Transmission Planning Strategies to Accommodate Renewables, presented at Renewable Energy Grid Operations, (with Johannes Pfeifenberger and Judy Chang), September 2017.

Blending In: The Role of Renewable Fuel in Achieving Energy Policy Goals, (with Marc Chupka and Philip Verleger Jr.), prepared for Growth Energy, August 2017.

Electrification: Emerging Opportunities for Utility Growth, (with Jurgen Weiss, Ryan Hledik, and Will Gorman), January 2017.

Valuation of Electric Power System Services and Technologies, (with M. Kintner-Meyer, J. Homer, P. Balducci, M. Weimar, Ira Shavel, Nicholas Powers, Yingxia Yang and Roger Lueken), prepared for U.S. Department of Energy, August 2016.

Peeking Over the Blendwall: An Analysis of the Proposed 2017 Renewable Volume Obligations, (with Marc Chupka, Nicholas Power, and Sarah Germain), prepared for Growth Energy, July 2016.

Impacts of Oregon's Coal Phase-Out on Coal Plant Economics in the Western U.S., presented at Oregon's Clean Electricity and Coal Transition Plan, July 2016.

Clean Energy Resource Options for Massachusetts to Meet GHG Reduction Goals under the Global Warming Solutions Act (GWSA): A Synthesis of Relevant Studies, (with Judy Chang and Will Gorman), prepared for the Barr Foundation, June 2016.

Benefits of the Southwest Intertie Project-North, (with Johannes Pfeifenberger, Judy Chang, Pablo Ruiz and Cady Wiltsie), prepared for Great Basin Transmission, LLC, March 2016.

EPA CPP Scenarios—What Texas Is Likely to Do, and the Impacts on ERCOT, presented at ERCOT Market Summit 2016 Pre-Summit Briefing, February 2016.

The Clean Power Plan: Implications for the Western Interconnect, presented at Optimizing Carbon Market Mechanisms in the Western Interconnect, (with Judy Chang and Marc Chupka), January 2016.

Issue Brief - The Clean Power Plan: Focus on Implementation and Compliance, (with Marc Chupka, Metin Celebi, Judy Chang, Ira Shavel, Kathleen Spees, Jurgen Weiss, Pearl Donohoo-Vallett and Michael Kline), January 2016.

Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, (with Sam Newell, Bruce Tsuchida, Akarsh Sheilendranath, Nicole Irwin and Lauren Regan), prepared for NYISO and New York Department of Public Service Staff, September 2015.

Lake Erie Connector Market Assessment Report, (with Judy Chang, Johannes Pfiefenberger and Akarsh Sheilendranath), prepared for ITC Lake Erie Connector LLC, May 2015.

Electricity Baseline Report for the U.S. Power System, (with Ira Shavel, Nicholas Powers and Yingxia Yang), for Pacific Northwest National Laboratory and U.S. Department of Energy, April 2015.

EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review, (with Jurgen Weiss, Toshiki Bruce Tsuchida, and Will Gorman), prepared for the Advanced Energy Economy Institute, February, 2015.

Nebraska Renewable Energy Exports: Challenges and Opportunities, (with Judy Chang and Johannes Pfeifenberger), prepared for the Nebraska Power Review Board, December 12, 2014.

Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment, (with Judy Chang and Johannes Pfeifenberger), prepared for The Electric Reliability Council of Texas (ERCOT), September 30, 2014.

Policy Brief - EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry, (with M. Celebi, K. Spees, S. Newell, D. Murphy, M. Chupka, J. Weiss, J. Chang, and I. Shavel), June 2014.

Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, prepared for PJM Interconnection, LLC (with S. Newell, K. Spees, J. Pefiefenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy), May 15, 2014.

2013 Offer Review Trigger Prices Study, prepared for ISO New England Inc. (with S. Newell and Q. Lao), October 2013.

Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process, (with J. Chang, J. Pfeifenberger, S. Newell, and T. Tsuchida), prepared for the Electric Reliability Council of Texas (ERCOT), October 2013.

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, (with J. Chang and J. Pfeifenberger), prepared for the Working Group for Investment in Reliable and Economic Electric Systems (WIRES), July 2013.

Managing Large-Scale Penetration of Intermittent Renewables, (with MIT Energy Initiative), April 2012.