ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pennsylvania Public Utility Commission	)	
Complainant,	)	Docket No. EL26-___-000
	)	
v.	)	
	)	
PJM Interconnection, LLC,	)	
Respondent	)	

DIRECT TESTIMONY

OF

ZACHARY MING

ON BEHALF OF THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

August 17, 2026

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AFFIDAVIT OF ZACHARY MING

1. Introduction

Q1. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A1. My name is Zachary Ming. My current position is Partner at Energy and Environmental Economics ("E3"). My business address is 44 Montgomery Street Suite 1250, San Francisco, California 94104.

Q2. PLEASE STATE ON WHOSE BEHALF YOU ARE FILING TESTIMONY.

A2. I am testifying as an expert witness in the areas of civil and environmental engineering, management science and engineering, and economics on behalf of the Pennsylvania Public Utility Commission ("PA PUC").

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A3. I have a Bachelor of Science degree in Civil and Environmental Engineering (Atmosphere and Energy program) with a Minor in Economics, and a Master of Science degree in Management Science and Engineering (Energy track), both from Stanford University, California. For 13 years I have held various roles at E3, an energy consulting firm specializing in the economics of the electricity system where I am currently a Partner. In addition to full-time consulting work at E3, I have taught a graduate-level course for eight years at Stanford University titled *Electricity Economics*.

Q4. PLEASE DESCRIBE YOUR QUALIFICATIONS AS IT RELATES TO THE ECONOMIC EVALUATION OF TRANSMISSION.

A4. In my role as a Partner at E3, I oversee projects involving transmission and resource planning, marginal cost analysis, market design, and rate design. I have authored several reports that evaluate the role that generation and transmission serve in reliably and cost-effectively meeting long-term system needs, including *Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets*,[1] *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*[2] and *Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future*.[3] I have also developed methods that quantify how generation resources can avoid or defer investments in transmission and distribution infrastructure.[4] I have worked with utilities to develop transmission rate designs that accurately reflect the costs of the customers being served, including in Nova Scotia and Alberta. Most broadly, I lead E3 teams to support clients to understand the current challenges facing the electricity system and to implement solutions that are economic and reliable.

[1] https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf.
[2] https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf.
[3] https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf.
[4] https://www.ethree.com/wp-content/uploads/2025/02/2024-ACC-Documentation-v1b_clean.pdf.

Q5. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC")?

A5. Yes, I have testified multiple times before FERC. My previous testimony has covered various topics related to transmission, rate design and wholesale markets in PJM, including the transmission tariff for co-located loads,[5] the capacity market price cap,[6] the participation of reliability must run ("RMR") units in the capacity market,[7] and PJM's filing to use marginal effective load carrying capability ("ELCC") as the basis for resource accreditation in the capacity market.[8] I have also testified to FERC on behalf of MISO in their proposal to implement the direct loss of load ("DLOL") methodology for resource accreditation,[9] and on behalf of generators regarding the pay-for-performance construct in ISO-NE.[10] Additionally, I have testified before state, provincial, and territorial public utility commissions in Oregon, Texas, South Carolina, Colorado, New Brunswick, and Puerto Rico on topics relating to reliability, resource adequacy, market design, and rate design.

Q6. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A6. The purpose of this testimony is to demonstrate why PJM's current methodology for quantifying the economic benefits of candidate market efficiency transmission projects is unjust and unreasonable because it discriminates between consumers in the PJM region. This discrimination occurs because PJM only considers the economic impact of proposed market efficiency projects to benefitting consumers

[5] Docket Nos. EL25-49-000, EL25-49-001, AD24-11-000, and EL25-20-000.
[6] Docket EL25-46-000.
[7] Docket EL24-148.
[8] Docket ER24-99-000.
[9] Docket ER24-1638.
[10] Docket EL25-106-000

and ignores economic costs to non-benefitting consumers. The result of this discrimination is market efficiency transmission projects that can increase consumer costs in aggregate at a time when a focus on affordability is paramount. My testimony proposes an alternative non-discriminatory methodology that considers the economic impacts to all consumers in PJM.

Q7. PLEASE PROVIDE AN OUTLINE OF YOUR TESTIMONY.

A7. My testimony is organized as follows:

- In Section 2, I provide background on the PJM transmission planning process with a particular focus on market efficiency projects;
- In Section 3, I outline why PJM's current method for quantifying the benefits of candidate market efficiency projects is unjust and unreasonable because it is discriminatory;
- In Section 4, I propose an alternative non-discriminatory methodology for quantifying the benefits of market efficiency projects that considers the economic impacts to all PJM consumers. Beyond my proposed replacement rate, I also provide longer-term considerations for PJM in terms of evaluating market efficiency projects; and
- In Section 5, I summarize my testimony and recommendations.

2. Background

Q8. PLEASE PROVIDE AN OVERVIEW OF TRANSMISSION PLANNING IN PJM.

A8. Transmission planning in PJM primarily occurs through the Regional Transmission Expansion Plan ("RTEP") process. This is a process run by PJM that identifies and evaluates candidate transmission projects that meet various grid needs. Projects are ultimately approved or rejected by the PJM Board after PJM evaluation and input from stakeholders.

Q9. WHAT TYPES OF PROJECTS ARE EVALUATED THROUGH PJM'S TRANSMISSION PLANNING PROCESS?

A9. PJM's transmission planning process evaluates candidate projects that meet four main categories of system needs:

- **Reliability:** PJM conducts power flow studies to identify potential future reliability issues such as thermal overloads, voltage violations, and stability concerns. PJM then develops transmission projects to addresses these issues through "baseline" transmission upgrades.
- **Market efficiency:** Stakeholders can propose candidate transmission projects designed to improve system economics that are not strictly necessary for reliability purposes. PJM uses production cost modeling to simulate how the system operates with and without candidate transmission projects to forecast the economic benefit of the project.

- **Operational:** PJM evaluates projects that transmission owners identify that may not resolve explicit NERC reliability violations but may improve system operations. Examples include enhancing transfer capability between zones, improving PJM's ability to manage resource outages, and ensuring the system can access sufficient flexibility from resources.
- **Public policy:** PJM evaluates projects that stakeholders propose that are necessary to achieve state or federal mandates, such as renewable portfolio standards. For example, PJM evaluates what transmission projects are required to deliver energy from new policy-driven resources (often remote renewables) to load centers.

Q10. PLEASE PROVIDE MORE DETAIL ON THE MARKET EFFICIENCY CATEGORY.

A10. In transmission planning, "market efficiency" projects are designed to improve system economics by facilitating the dispatch of the lowest cost generation. The configuration of the existing transmission system may, in some cases, prevent the lowest cost generation from dispatching due to constraints on the transmission system. The result is "congestion." PJM says that its RTEP market efficiency planning process is designed to "identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact."[11]

[11] PJM Manual 14B: PJM Region Transmission Planning Process, https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf, page 53.

Transmission planners evaluate the benefits of candidate market efficiency transmission projects through forward-looking analysis that compares grid dispatch costs with and without the project.

Q11. HOW DO MARKET EFFICIENCY PROJECTS RELATE TO THE BROADER PURPOSE OF REGIONAL TRANSMISSION ORGANIZATIONS?

A11. Before the creation of Regional Transmission Organizations such as PJM, traditional vertically-integrated utilities operated under a cost-of-service regulatory framework that required them to act prudently. One aspect of prudence entails that utilities seek to provide electricity service to customers at the lowest reasonable cost, subject to meeting standards such as reliability and environmental compliance.

The advent of Regional Transmission Organizations in many cases moved the transmission planning function from individual member utilities to the Regional Transmission Organization itself, but the objectives of least-cost planning remain the same. FERC Order No. 890 explained that, when planning to serve load, a prudent transmission provider should consider whether "transmission upgrades or other investments can reduce the overall costs of serving native load," including upgrades that "reduce congestion (redispatch) costs or integrate efficient new resources."[12] So, in the context of PJM, it has an obligation to plan transmission in a manner that minimizes the cost of electricity across the region.

[12] https://www.ferc.gov/sites/default/files/2020-05/890.pdf, page 310.

Q12. WHAT ARE THE GENERAL METHODS USED ACROSS THE ELECTRICITY INDUSTRY FOR QUANTIFYING THE ECONOMIC BENEFITS OF A MARKET EFFICIENCY TRANSMISSION PROJECT?

A12. There are two general approaches to quantifying the economic benefits of a transmission project: a societal perspective or a consumer perspective.[13] The choice between these two perspectives is ultimately a policy decision about whose welfare should be considered.

A *societal* approach quantifies the value of a candidate transmission project to both producers (i.e., generators) and consumers (i.e., loads). The societal value includes how much a transmission project can both decrease energy dispatch costs and installed capacity costs. The decrease in dispatch costs is generally calculated by running a production cost model with and without the candidate transmission project and calculating the difference in total production costs between these two cases. The decrease in capacity costs is generally calculated by quantifying how much the transmission reduces the required quantity of installed capacity to meet the reliability requirement due to improved sharing of capacity between transmission zones.[14]

A *consumer* approach quantifies the value of a candidate transmission project to loads and does not consider the impact to producers (i.e., generators). The benefits to consumers in this approach are generally calculated by quantifying how the *prices* that loads pay for electricity can change with and without the

[13] https://www.brattle.com/wp-content/uploads/2021/06/The-Benefits-of-Electric-Transmission-Identifying-and-Analyzing-the-Value-of-Investments.pdf, page 4.

[14] https://www.ercot.com/files/docs/2024/05/23/E3_ERCOT_Congestion_Cost_Savings_Test_for_Economic_Transmission_Report_March_2024.pdf, page 27.

transmission project. Price changes are also calculated using production cost modeling. Within this general method, some common industry approaches account for the fact that changing prices through reduced congestion may reduce the revenues that ISOs collect by selling the financial rights to congestion. Since these revenues are allocated to loads, reductions in these revenues are a cost to consumers.[15] It is important to note that the energy and capacity prices that consumers pay for wholesale electricity are just one portion of the total rates that consumers pay, with the other primary portions being the cost of transmission and distribution to deliver the electricity.

These two general approaches (societal and consumer) can yield results that differ quite dramatically from each other. For example, a candidate transmission project could theoretically yield very little societal benefits but very large consumer price benefits if it relieves a small amount of congestion on a particular constraint that significantly reduces energy prices on the other side. On the other hand, it is also possible for a candidate transmission project to provide societal benefits while *increasing* overall energy prices, even before accounting for the cost of the transmission project itself. This can occur when all of the societal benefits accrue to producers (i.e., generators) through higher prices upstream of the new transmission.

[15] *Ibid*.

Q13. HOW ARE THESE CALCULATED BENEFITS USED IN THE SELECTION OF MARKET EFFICIENCY PROJECTS?

A13. First, the transmission planner must select one (or a combination) of the benefit approaches that I describe above as the economic benefits of the market efficiency project. Second, the transmission planner must compare these benefits to the cost of the candidate transmission project to calculate a benefit-cost ratio of the project. To account for the uncertainty associated with forecasted benefits, many RTOs set the required benefit-cost ratio threshold at greater than 1.0 (e.g., 1.25).

Q14. HOW DOES PJM CURRENTLY EVALUATE AND SELECT MARKET EFFICIENCY PROJECTS?

A14. PJM forecasts benefits for a candidate market efficiency transmission project (as described above) and calculates the net present value of these benefits over a 15-year horizon. PJM then compares these benefits to the net present value of costs of the transmission project over the same 15-year period. PJM requires a benefit-cost ratio of greater than or equal to 1.25 for the project to move forward for approval by the PJM Board.

Q15. WHAT METHOD DOES PJM USE FOR CALCULATING THE BENEFITS OF CANDIDATE MARKET EFFICIENCY TRANSMISSION PROJECTS.

A15. PJM's methodology for calculating the benefits of candidate market efficiency projects differs for "regional" projects (at or greater than 230 kV) and "lower voltage" (also known as "subregional") projects (less than 230 kV).[16] PJM's RTEP

[16] Monitoring Analytics, "State of the Market Report for PJM," 2025 Annual State of the Market Report for PJM, pages 778 and 779.

and market efficiency studies often focus on 345 kV and above for major congestion relief. For regional projects, PJM uses a combination of both the "societal" and "consumer" approaches that I describe above. Specifically, PJM calculates the average of societal benefits and PJM's version of consumer benefits for both energy and capacity markets (described below).[17]

For "lower voltage" projects, PJM simply uses their version of consumer benefits of the project.[18]

An illustration of these formulas is provided in Table 1 below.

Table 1: Current PJM Market Efficiency Benefit Formulas

Project Type	Benefits Formula
Lower Voltage	Change in Load Energy Payment + Change in Load Capacity Payment
Regional	(0.5 * Change in Total Energy Production Cost) + (0.5 * Change in Load Energy Payment) + (0.5 * Change in Total System Capacity Cost) + (0.5 * Change in Load Capacity Payment)

Note: Under PJM's current framework, the Change in Load Energy Payment and Change in Load Capacity Payment terms only include zones that show a decrease in payment (i.e., zones that benefit).

Q16. PLEASE PROVIDE MORE DETAIL ON HOW PJM CALCULATES CONSUMER BENEFITS I.E., THE CHANGE IN LOAD ENERGY PAYMENT AND CHANGE IN LOAD CAPACITY PAYMENT.

A16. PJM calculates consumer benefits by calculating the change in load energy payment and change in load capacity payment by zone.[19] For some zones, load payments increase (which is a cost to those consumers) and in some zones load payments decrease (which is a benefit to those consumers). This observation that transmission

[17] PJM refers to consumer costs as "load energy payments" or "load capacity payments".
[18] PJM Manual 14B: PJM Region Transmission Planning Process, https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf, page 112.
[19] PJM calculates the impacts of transmission expansion across all zones in its footprint, including AECO, AEP, APS, BGE, COMED, DAY, DEOK, DOM, DPL, DUQ, EKPC, FE-ATSI, HTP, JCPL, METED, NEPT, OVEC, PECO, PENELEC, PEPCO, PLGRP, PSEG, RECO, and VFT (see 20230511_PJM Zone Map). These zones generally correspond to load-serving entities ("LSEs") or distribution utilities and are each associated with a locational marginal price (see PJM Locational Marginal Pricing Map).

expansion makes some consumers better off who are downstream of the candidate transmission project and some worse off who are upstream of the candidate transmission project is well-documented in the academic literature.[20]

When calculating the total consumer benefits for both energy and capacity, ***PJM only includes zones that experience a benefit*** (i.e., decrease in load payments). In other words, PJM excludes zones from the overall benefit calculation that experience an increase in their energy and capacity load payments.[21]

Q17. WHAT IS THE RESULT OF EXCLUDING ZONES THAT EXPERIENCE HIGHER LOAD PAYMENTS FROM PJM'S BENEFIT CALCULATION?

A17. The simple result is that PJM's benefit calculations for market efficiency projects do not in fact represent consumer benefits for all consumers in the PJM region. Instead, they just represent benefits for the subset of consumers who stand to benefit from the project. As a result, PJM's methodology by definition over-values transmission to consumers in aggregate because it only considers the impact to those who benefit; in some cases, it is possible for PJM's methodology to show consumer "benefits" for a transmission project that actually *increase* costs for

[20] For example, Baldick et al. (https://www.analysisgroup.com/globalassets/insights/publishing/blue_ribbon_panel_final_report.pdf, page 24) remark:

> *"One last point to make with regard to benefits is that many transmission projects will not benefit everyone – at least in the short run – and can in fact negatively impact some network users due to the impact on energy prices. In the discussion above, for example, we focused on a local generator who is harmed by a decrease in local prices. There are also circumstances where an exporting region could experience an increase in prices. This would benefit producers and cost consumers in the exporting region. These impacts are transfers, but do represent a real cost to the generators or consumers involved, and therefore can raise opposition to individual projects based upon local interests."*

[21] PJM Manual 14B: PJM Region Transmission Planning Process, https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf, pages 112 & 113.

consumers in aggregate across the PJM region. I provide an example to illustrate this later in my testimony.

Q18. IS THERE ANY PRECEDENT FOR PJM'S APPROACH OF ONLY INCLUDING CONSUMER IMPACTS FOR A SUBSET OF CONSUMERS WHEN EVALUATING COST-EFFECTIVENESS?

A18. No. No other ISO in North America calculates consumer benefits for only a subset of consumers. All ISOs that use a consumer benefit metric (many use a societal benefit metric) include the impact to *all* consumers across their geographic footprint. I provide more detail on the specific methodologies used by other ISOs in the Appendix.

Q19. WHAT IS PJM'S STATED RATIONALE FOR ONLY INCLUDING CONSUMER IMPACTS FOR A SUBSET OF CONSUMERS?

A19. PJM has provided at least two reasons for only including consumer impacts for a subset of consumers.

First, PJM has stated that "PJM believes this … market efficiency benefit calculation will more appropriately align the benefits with the [cost allocation] of the facilities…"[22] PJM's argument appears to be that because benefitting zones pay a larger (though not entire) share of market efficiency transmission projects than non-benefitting zones, only the interests of benefitting zones should be considered.[23]

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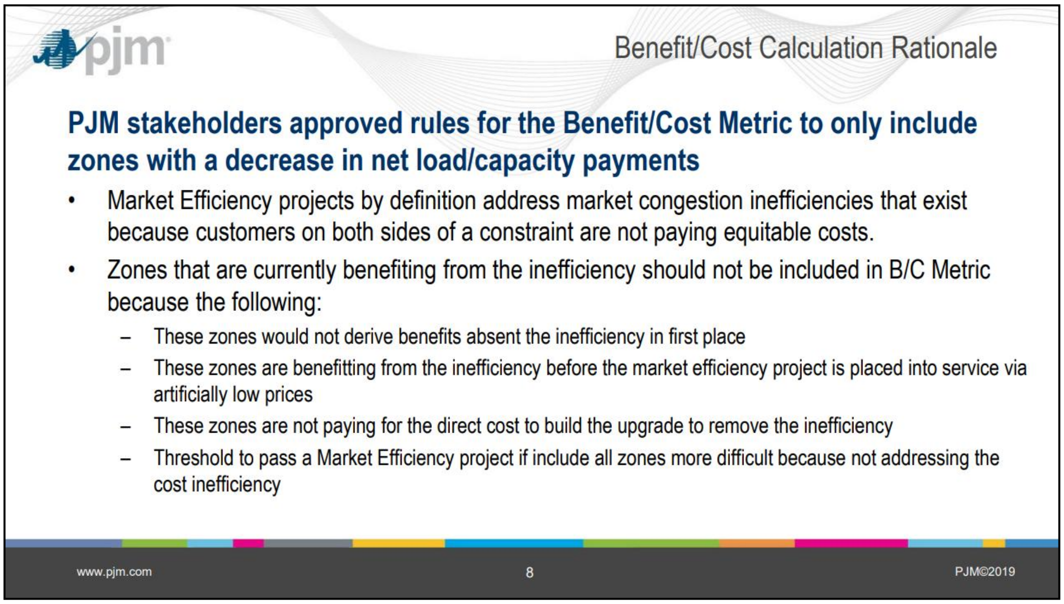
[22] PJM Transmittal Letter, FERC Docket ER14-1394, 4/30/2014, page 8.

[23] The cost of regional facilities is allocated 50% based on load ratio share across the entire region and 50% to benefitting zones based on their share of the benefits https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol2.pdf, page 779.

Second, PJM has provided rationale that appears to characterize congestion as inherently inefficient and inequitable. This is shown in Figure 1.

Figure 1: PJM Market Efficiency Benefit/Cost Calculation Rationale[24]



Q20. IS CONGESTION INHERENTLY INEFFICIENT?

A20. No, transmission congestion is *not* inherently economically inefficient. Some amount of congestion is a natural and economic characteristic of electricity systems. Seeking to eliminate congestion for its own sake results in transmission investments that cost more than the benefits of relieving the congestion. The Alberta Electric System Operator recently recognized this when it decided to "move away from the [then] current zero-congestion transmission planning standard to an optimally planned transmission planning standard."[25] The Australian Energy Security Board[26] has also made similar observations before in saying:

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[24] https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/mepetf/20190701/20190701-item-05-b-c-ratio-background.pdf?utm_source=chatgpt.com, page 8.
[25] https://aesoengage.aeso.ca/optimal-transmission-planning
[26] Comprised of the heads of the Australian Energy Market Commission, the Australian Energy Regulator, and the Australian Energy Market Operator.

> *"That said, congestion is common in all regions of the [Australian National Energy Market], and for good reason. Building transmission capacity is expensive and imposes costs on the communities that the transmission lines run through. If not carefully targeted, the cost of building transmission can very often exceed the reduction in the cost of congestion. Just like we do not have unlimited numbers of hotel rooms because building hotels is expensive, we also do not have unlimited transmission capacity."*[27]

For these reasons, no ISOs or utilities currently plan transmission to eliminate or reduce congestion for its own sake. Rather, ISOs and utilities only seek to eliminate or reduce congestion when the cost of the transmission project is less than the (avoided) cost of congestion. When the cost of congestion is less than the cost of the transmission project required to relieve it, the congestion is economically efficient.

Q21. DOES CONGESTION YIELD "ARTIFICIALLY LOW PRICES" AS SUGGESTED IN PJM'S SLIDE ABOVE?

A21. PJM's assertion that locational marginal prices that vary by location yield "artificially low prices" is unfounded. Such an assertion is inconsistent with economic theory and mischaracterizes how electricity markets are designed to function. Prices at a particular location are not artificial but rather reflect the direct result of serving load at a specific location while accounting for the physical realities of transmission and generation. Prices that differ by location are a natural

[27] https://www.datocms-assets.com/32572/1677794694-esb-congestion-management-cost-benefit-analysis.pdf, page 16.

(not artificial) feature of an economically efficient electricity grid that minimizes costs in aggregate for all consumers.

Q22. DID FERC APPROVE PJM'S METHODOLOGY FOR ONLY INCLUDING CONSUMER IMPACTS FOR A SUBSET OF BENEFITTING CONSUMERS?

A22. FERC approved PJM's methodology through a "Delegated Letter Order" that was issued by FERC staff under authority delegated by the Commissioners, rather than standard Commission Order that is voted on and issued by the Commissioners themselves.[28]

[28] Delegated Letter Order, Docket No ER14-1394-000 (Issued April 23, 2014).

3. Current Selection Framework is Unjust and Unreasonable

Q23. DOES PJM'S CURRENT METHOD FOR CALCULATING THE BENEFITS OF MARKET EFFICIENCY TRANSMISSION PROJECTS CONSIDER THE IMPACTS TO ALL PJM CONSUMERS IN A NON-DISCRIMINATORY MANNER?

A23. No. PJM's methodology for calculating the benefits of market efficiency transmission projects only considers the impacts to consumers in zones that are beneficiaries (i.e. experience lower energy or capacity costs) while ignoring the impacts to consumers in zones that experience higher costs. This discriminatory treatment is unjust and unreasonable and is inconsistent with the mandate of the Federal Power Act.

Q24. WHAT IS THE FEDERAL POWER ACT'S STANDARD ON DISCRIMINATION?

A24. The principle of treating all consumers equally was so important to Congress that it mentions the principle of non-discrimination nineteen times in the Federal Power Act. For example, it states that "no public utility shall … make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage [or] maintain any unreasonable difference … between localities."[29]

[29] Federal Power Act § 205(b), 16 U.S.C. § 824d(b).

Q25. HOW DOES PJM'S METHODOLOGY VIOLATE THE FEDERAL POWER ACT'S STANDARD ON DISCRIMINATION?

A25. PJM's methodology for calculating the benefits of market efficiency projects only considers the impacts to benefitting consumers and ignores the costs to non-benefitting consumers. This methodology that does not equally consider the impacts to all consumers in PJM is discriminatory and therefore unjust and unreasonable.

By discriminating against a subset of loads, PJM has effectively excluded a subset of consumers from their "consumer" benefits metric. Instead of planning transmission in the public interest of all consumers, PJM is effectively acting in the interests of a subset of consumers who would benefit from a particular project, even at the expense of other consumers who may be made even worse off.

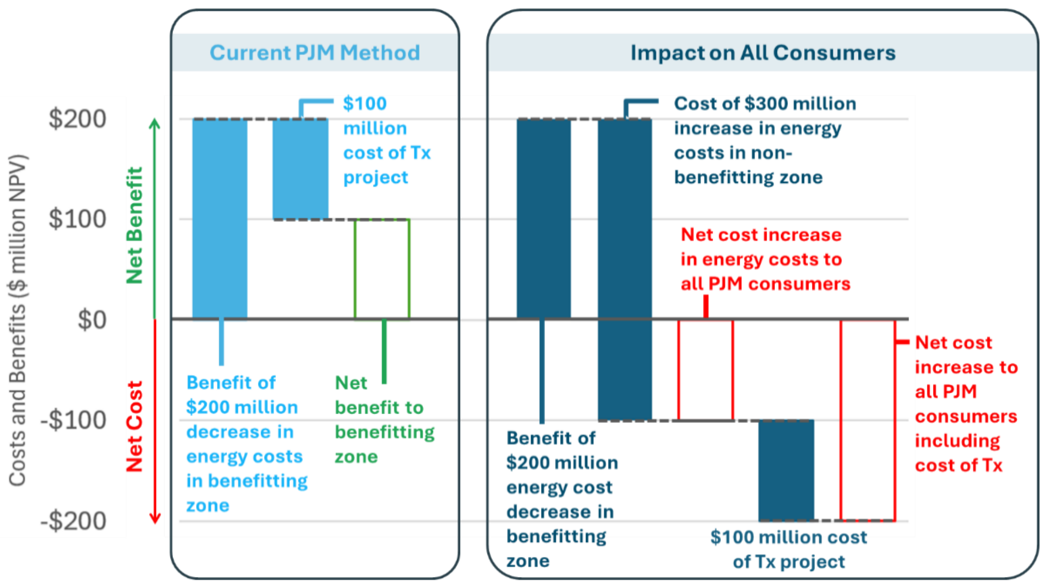
Q26. WHAT IS THE RESULT OF PJM'S METHODOLOGY?

A26. Aside from the unjustness of the discrimination itself, PJM's methodology over-values transmission to consumers in aggregate because it only considers the impact to those who benefit; in some cases, this methodology yields projects that **increase costs for consumers in aggregate in PJM**, with costs defined as load energy and capacity costs plus market efficiency transmission project costs. In fact, PJM's methodology can even yield the non-sensical outcome of market efficiency projects that increase load energy and capacity costs across the entire region *before* even counting the cost of the transmission project itself. In other words, PJM consumers in aggregate can be forced to pay for transmission projects that actually increase their energy and capacity costs.

Q27. HOW CAN PJM'S METHODOLOGY YIELD MARKET EFFICIENCY PROJECTS THAT INCREASE CONSUMER COSTS IN AGGREGATE ACROSS PJM?

A27. Imagine a candidate market efficiency project that costs $100 million and increases consumer energy costs in one zone by $300 million and decreases consumer energy costs by $200 million in another zone.[30] As illustrated in Figure 2, such a project would pass PJM's market efficiency test but would increase energy costs for PJM consumers in aggregate. Including the cost of the transmission project itself would *further* increase costs for all PJM consumers.

Figure 2: Illustration of How PJM Method Can Increase Consumer Costs

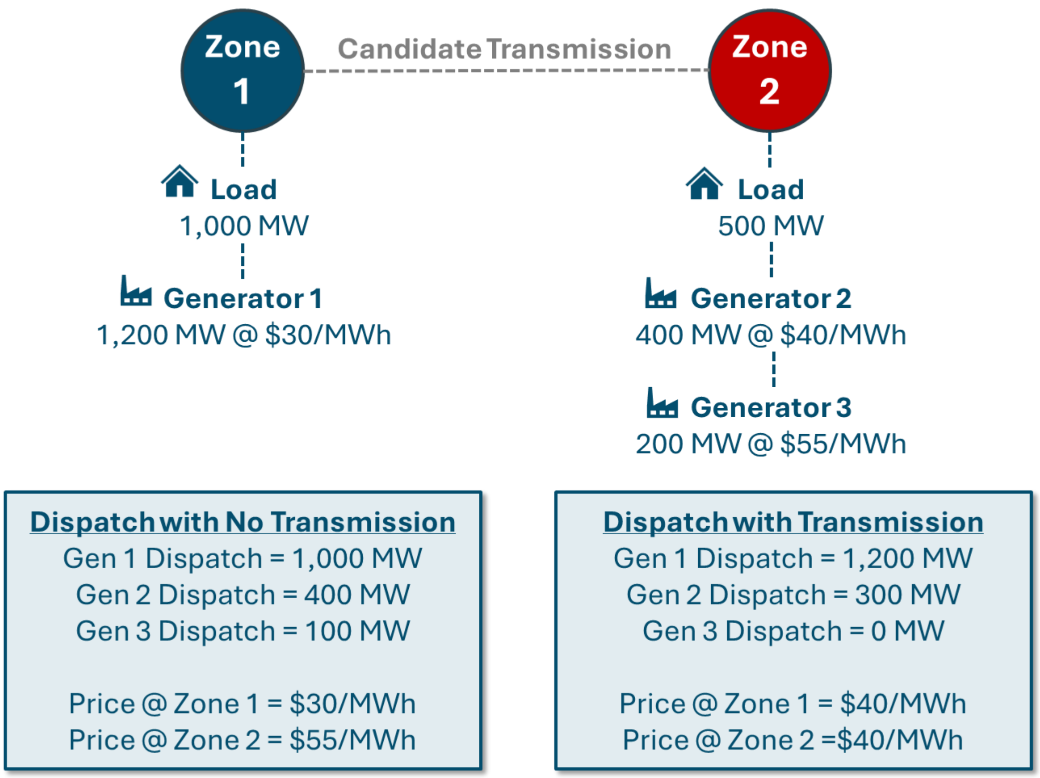


[30] All dollar values on a net present value basis

Q28. CAN YOU CREATE AN EXAMPLE SHOWING A MARKET EFFICIENCY PROJECT THAT WOULD BE APPROVED UNDER PJM'S CURRENT METHODOLOGY THAT INCREASES CONSUMER COSTS?

A28. Yes. I have constructed the simplest example possible to illustrate this potential outcome. The graphic below represents a two-zone electricity system with loads and generators in each zone. I have illustrated the dispatch and prices for a system *with* and *without* a candidate transmission project could connect these two zones. These values are explained more in the tables in the subsequent pages.

Figure 3: Two-Zone System Illustration



Using PJM's existing methodology for evaluating candidate market efficiency projects, I demonstrate in the table below how PJM would calculate a benefit-cost ratio of greater than 1.25 for this project as either a "regional" or "lower voltage" project despite this project increasing consumer costs.

Table 2: Illustrative Two-Zone Example – System Assumptions, Dispatch, and Cost per Hour

		Units	Zone 1	Zone 2	System Total	Formula / Notes
System Assumptions						
Load		*MW*	1,000	500	**1,500**	Hourly load
Generator 1	**Capacity**	*MW*	1,200			Capacity of generator in Zone 1
	Marginal Cost	*$/MWh*	$30			Marginal cost of generator in Zone 1
Generator 2	**Capacity**	*MW*		400		Capacity of first generator in Zone 2
	Marginal Cost	*$/MWh*		$40		Marginal cost of first generator in Zone 2
Generator 3	**Capacity**	*MW*		200		Capacity of second generator in Zone 2
	Marginal Cost	*$/MWh*		$55		Marginal cost of second generator in Zone 2
Scenario A: No Transmission						
Generator 1 Dispatch		*MW*	1,000			Generator 1 serves all load in Zone 1
Generator 2 Dispatch		*MW*		400		Generator 2 dispatched at full capacity
Generator 3 Dispatch		*MW*		100		Generator 3 serves remainder of Zone 2 load
Locational Marginal Price (LMP)		*$/MWh*	$30	$55		LMP = Marginal Cost of last unit dispatched in each zone
Load Energy Payments		*$/hr*	$30,000	$27,500	**$57,500**	Load × LMP
Generator Margins		*$/hr*	$0	$6,000	**$6,000**	Dispatch × (LMP - Marginal Cost), for each generator, summed by zone
Production Cost		*$/hr*	$30,000	$21,500	**$51,500**	Dispatch × Marginal Cost, for each generator, summed by zone
Scenario B: With Transmission						
Generator 1 Dispatch		*MW*	1,200			Generator 1 runs at full capacity to serve all load in Zone 1 and exports 200 MW to Zone 2
Generator 2 Dispatch		*MW*		300		Generator 2 serves 300 MW of Zone 2 load after 200 MW of imports from Zone 1
Generator 3 Dispatch		*MW*		–		Generator 3 is no longer needed; displaced by cheaper Generator 1 energy
Locational Marginal Price (LMP)		*$/MWh*	$40	$40		LMPs equalize across zones; set by marginal unit across the regions (Generator 2). Relative to "No Transmission", this increases prices in Zone 1 and decreases prices in Zone 2
Generator Margins		*$/hr*	$12,000	$0	**$12,000**	Dispatch × (LMP - Marginal Cost), for each generator, summed by zone
Load Energy Payments		*$/hr*	$40,000	$20,000	**$60,000**	Load × LMP by zone
Production Cost		*$/hr*	$36,000	$12,000	**$48,000**	Dispatch × Marginal Cost, for each generator, summed by zone

Table 3: Illustrative Two-Zone Example – Transmission Project Cost-Benefit Analysis

Benefits can be positive or negative depending on the item and are shown in green. Costs can be positive or negative and are shown **in red.**

		Units	Zone 1	Zone 2	System Total	Formula / Notes
Hourly Impact of Transmission (green cells represent benefits)						
Generator Margins		*$/hr*	+ $12,000	– $6,000	**+ $6,000**	Generator Margins from Scenario B minus Scenario A, for each zone; positive value represents an increase in margins, which is a benefit to generators
Load Energy Payments		*$/hr*	+ $10,000	– $7,500	**+ $2,500**	Load Energy Payments from Scenario B minus Scenario A, for each zone; positive value represents an increase in load energy payments, which is a cost to loads
Production Cost		*$/hr*	+ $6,000	– $9,500	**– $3,500**	Production Cost from Scenario B minus Scenario A, for each zone; negative value represents a decrease in production costs, which is a benefit to society
Net Present Value (NPV) Calculation Input, Consistent with PJM Transmission Economic Evaluation						
Evaluation Period		*years*	15	15	**15**	15-year study horizon consistent with PJM Market Efficiency evaluation
Discount Rate		*%*	7.2%	7.2%	**7.2%**	Rate used to discount future benefits and costs (PJM's 2024/2025 discount rate)
Present Value (PV) Factor		*factor*	8.994	8.994	**8.994**	(1 - (1 + Discount Rate)^-Evaluation Period) ÷ Discount Rate
NPV of Impact of Adding Transmission (green cells represent benefits)						
Generator Margins		*$M*	+ $945	– $473	**+ $473**	Hourly Generator Margins Impact × 8,760 hrs/yr × annuity factor (8.994); positive value represents an increase in margins, which is a benefit to generators
Load Energy Payments		*$M*	+ $788	–$591	**+ $197**	Hourly Load Energy Payment Impact × 8,760 hrs/yr × annuity factor (8.994); positive value represents an increase in load energy payments, which is a cost to loads
Production Cost		*$M*	+ $473	–$748	**– $276**	Hourly Production Cost Impact × 8,760 hrs/yr × annuity factor (8.994); negative value represents a decrease in production costs, which is a benefit to society
Transmission Project Net Present Value (NPV) Costs						
Transmission Project NPV Costs		*$M*			**+ $300**	**Assumption:** Present value of capital and fixed cost of the transmission project
Transmission Net Economic Benefits (green cells represent net benefits)						
Total Consumer Net Benefit		*$M*			**– $497**	System Load Energy Payments cost ($197M) + Transmission Project Cost ($300M); consumers experience $497M net cost, which is a -$497 net benefit
Total Societal Net Benefit		*$M*			**– $24**	Production Cost NPV net benefit ($276M) – Transmission Project Cost ($300M); society experiences $24M net cost, which is a -$24M net benefit
Benefit-Cost (B/C) Ratios						
PJM Method	**Lower Voltage**	*ratio*			**1.97**	Zone 2 Load Energy Payments NPV net benefit ($591M) ÷ Transmission Project NPV cost ($300M); project passes PJM 1.25 B/C threshold
	Regional	*ratio*			**1.44**	(50% × Zone 2 Load Energy Payments NPV net benefit ($591M) + 50% × Production Cost NPV net benefit ($276M)) ÷ Transmission Project NPV cost ($300M); project passes PJM 1.25 B/C threshold
E3 Method	**Lower Voltage**	*ratio*			**(0.66)**	System Load Energy Payments NPV net benefit (-$197M) ÷ Transmission Project NPV cost ($300M); project does not pass
	Regional	*ratio*			**0.13**	(50% × System Load Energy Payments NPV net benefit (-$197M) + 50% × Production Cost NPV net benefit ($276M)) ÷ Transmission Project NPV cost ($300M); project does not pass PJM 1.25 B/C threshold

Q29. IS THE POTENTIAL FOR OUTCOMES LIKE THIS MERELY THEORETICAL?

A29. No. There are multiple real-world projects in PJM where the concerns that I raise above have occurred. For example, an enhancement proposed by Transource Energy LLC (what PJM referred to as "Project 9A"), yielded the following results as described by the PJM Independent Market Monitor ("IMM"):

> *"Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the benefit/cost ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis. The initial study had a benefit to cost ratio of 2.48, with a capital cost of $340.6 million. The sum of the positive (energy cost reductions) effects was $1,188.07 million. The sum of negative effects (energy cost increases) was $851.67 million. The net actual benefit of the project in the study was therefore $336.40 million, not the $1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds."*[31]

Another example is the "Project 644+908" Multi-Driver project in the COMED-NIPSCO-AEP area, which was proposed as part of the 2022 Regional Transmission Expansion Plan. The Independent Market Monitor once again showed how the results would have drastically changed if PJM accounted for the impact to all consumers rather than just the beneficiaries of the transmission:

> *"The benefit/cost analysis used in the multi driver review is the same flawed benefit/cost analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the*

[31] https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, page 2.

present value of positive (energy cost reductions to some loads) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases to other loads), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM, even ignoring the use of changes in congestion rather than changes in production costs. Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd Zone. Based on the requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi driver project should have been rejected."[32]

Q30. BESIDES YOURSELF, HAVE OTHERS MADE ARGUMENTS THAT IT IS UNJUST AND UNREASONABLE TO ONLY INCLUDE BENEFITS FOR A SUBSET OF CONSUMERS IN THE PJM REGION?

A30. Yes. The IMM has repeatedly raised this issue in its State of the Market and FERC filings. For example, the IMM has stated that:

"[t]he current rules governing the benefit/cost analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules explicitly ignore the increased zonal load costs that a project may create ... These flaws have contributed to PJM approving market efficiency projects with forecasted, and realized, costs that are higher than the forecasted benefits."[33]

Q31. ONE RATIONALE PJM HAS PROVIDED FOR ITS EXISTING METHODOLOGY IS TO "ALIGN" THE MARKET EFFICIENCY BENEFIT

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[32] Monitoring Analytics, "2024 State of the Market Report for PJM", 2024 State of the Market Report for PJM, page 715. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf

[33] https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, page 2.

DETERMINATION WITH COST ALLOCATION. IS THIS RATIONALE COMPELLING?

A31. No, this rationale is not compelling for two reasons.

First, regardless of who is paying for the transmission project, it is unjust and unreasonable for PJM to facilitate a discriminatory race-to-the-bottom framework that incentivizes consumers to pursue projects in their own interest that ultimately increase costs for everybody. In other words, inefficiently building transmission from one zone to another will decrease prices in the downstream zone. This itself will increase the economics of building additional transmission to a yet further downstream zone, which increases prices in the original downstream zone.

In the illustrative two-zone example that I created above, benefitting zones experience an energy market benefit of $591 million (before the cost of the transmission itself) while non-benefitting zones experience an energy market cost of $788 million. Why not just skip the transmission project altogether and simply take $600 million from the non-benefitting zone and give it directly to the benefiting zone? Both zones would be better off than building the transmission. Clearly such a proposition is nonsensical, but the mere possibility that it exists demonstrates that the status quo can yield wasteful transmission investment.

Second, under PJM's current methodology, "regional" market efficiency projects allocate half of transmission costs to *all* zones, not just beneficiaries. This shows that the cost allocation is not "aligned" with benefit determination by only allocating costs to the zones that benefit. Forcing zones that experience higher energy costs to pay for the transmission lines that cause them adds insult to injury.

Q32. ANOTHER RATIONALE PJM HAS PROVIDED FOR ITS EXISTING METHODOLOGY IS THAT MARKET EFFICIENCY PROJECTS ADDRESS "MARKET CONGESTION INEFFICIENCIES" AND THAT "ZONES THAT ARE CURRENTLY BENEFITTING FROM THE INEFFICIENCY SHOULD NOT BE INCLUDED IN THE B/C RATIO BECAUSE … THESE ZONES WOULD NOT DERIVE BENEFITS ABSENT THE INEFFICIENCY IN THE FIRST PLACE."[34] IS THIS RATIONALE COMPELLING?

A32. No. PJM's rationale above appears to be implying that congestion is inherently "inefficient" and that, by extension, less congestion is more efficient. However, as I describe above, congestion itself is not necessarily inefficient, and in fact some congestion *is* efficient. Economic efficiency seeks to maximize societal benefits. To the extent that the cost of congestion is less than the transmission project required to relieve it, then the congestion is efficient and is part of a least-cost electricity system.

Q33. WHAT IS YOUR OVERALL ASSESSMENT OF PJM'S CURRENT METHODOLOGY FOR CALCULATING THE BENEFITS OF MARKET EFFICIENCY TRANSMISSION PROJECTS?

A33. PJM's methodology for calculating the benefits of market efficiency transmission projects is unjust and unreasonable because:

- It discriminates between benefitting and non-benefitting consumers;
- It can yield projects that increase aggregate consumer costs in PJM. At a time when electricity system affordability is a paramount concern, it is

[34] https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/mepetf/20190701/20190701-item-05-b-c-ratio-background.pdf?utm_source=chatgpt.com, page 8.

unreasonable for PJM to use planning methods that unnecessarily increase consumer costs;

- It has no precedent in any other RTO, each of which consider system-wide impacts under either a societal or consumer benefits perspective.
- It does not recognize that some congestion is efficient and present in a least-cost electricity system. It is for this reason that no utilities or RTOs in North America seek to eliminate or minimize congestion for its own sake.

4. Proposed Replacement Rate

Q34. HOW SHOULD PJM RECTIFY THE SHORTCOMINGS OF THEIR CURRENT MARKET EFFICIENCY BENEFITS DETERMINATION FRAMEWORK?

A34. To rectify the unjust and unreasonable design of PJM's current framework, PJM should include the impact of all (benefitting and non-benefitting) zones when calculating consumer benefits of market efficiency projects. This approach will ensure non-discriminatory treatment between all PJM consumers.

Q35. WHAT IS THE OUTCOME OF YOUR PROPOSED CHANGE?

A35. The outcome of my proposed change (aside from rectifying the inherent discrimination) will very simply ensure that PJM does not overvalue market efficiency projects, avoiding the outcome where PJM identifies market efficiency projects that increase aggregate consumer costs in PJM.

Q36. PLEASE PROVIDE THE SPECIFIC CHANGE THAT PJM SHOULD IMPLEMENT IN ITS OPERATING AGREEMENT.

A36. To rectify the unjustness and unreasonableness of the current Operating Agreement, PJM should revise the definitions of "Change in Load Energy Payment" and "Change in Load Capacity Payment" in Schedule 6, Section 1.5.7 of the Operating Agreement.[35]

Specifically, PJM should delete the following sentence from the definition of Change in Load Energy Payment:

[35] https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf.

"The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment."[36]

PJM should also delete the following sentence from the definition of Change in Load Capacity Payment:

"The Change in the Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment."[37]

With those deletions, PJM's existing benefit formulas would remain the same as they are currently, shown again in Table 4. The only difference is that the benefit formulas will consider the *overall* benefit to PJM customers rather than only focusing on the subset of zones that benefit from the proposed transmission.

Table 4: Current PJM Market Efficiency Benefit Formulas

Project Type	Benefits Formula
Lower Voltage	Change in Load Energy Payment + Change Load Capacity Payment
Regional	(0.5 * Change in Total Energy Production Cost) + (0.5 * Change in Load Energy Payment) + (0.5 * Change in Total System Capacity Cost) + (0.5 * Change in Load Capacity Payment)

Q37. WOULD YOUR PROPOSED REPLACEMENT RATE RESULT IN A JUST AND REASONABLE MARKET EFFICIENCY PROJECT SELECTION FRAMEWORK?

A37. Yes. The proposed replacement rate would result in a just and reasonable market efficiency selection framework by eliminating the discriminatory treatment that makes PJM's current methodology unjust and unreasonable.

[36] https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf, pages 597-599.
[37] Ibid.

As discussed above, PJM's current methodology is unjust and unreasonable because it excludes zones that experience a cost increase from the consumer benefit calculation while including zones that experience a cost decrease. This asymmetric treatment discriminates between PJM consumers based solely on whether they benefit from a proposed project. Removing the two sentences identified above eliminates this discrimination by requiring PJM to calculate consumer benefits on a system-wide basis, treating all zones the same regardless of whether they benefit or are harmed.

My proposed change is also consistent with the practice of every other North American ISO and RTO reviewed in the Appendix. No other jurisdiction excludes zones with cost increases from its benefit calculation, regardless of the benefit metric—whether a societal or consumer perspective.

Q38. WOULD IMPLEMENTING YOUR PROPOSED REPLACEMENT RATE TO THE PJM OPERATING AGREEMENT HAVE ANY BROADER IMPLICATIONS ON THE FRAMEWORKS USED IN OTHER RTO/ISO'S?

A38. No. As the jurisdictional review in the Appendix demonstrates, PJM is currently the *outlier* among all RTO/ISOs in in its evaluation of market efficiency transmission projects. No other RTO/ISO excludes zones with cost increases from its benefit calculation. Rectifying this discriminatory treatment in PJM's current framework would bring PJM's methodology in-line with other RTO/ISOs and would not have any broader implications on the frameworks in other RTO/ISOs.

Q39. WOULD YOUR REPLACEMENT RATE ELIMINATE OR IMPEDE MARKET EFFICIENCY PROJECTS IN PJM?

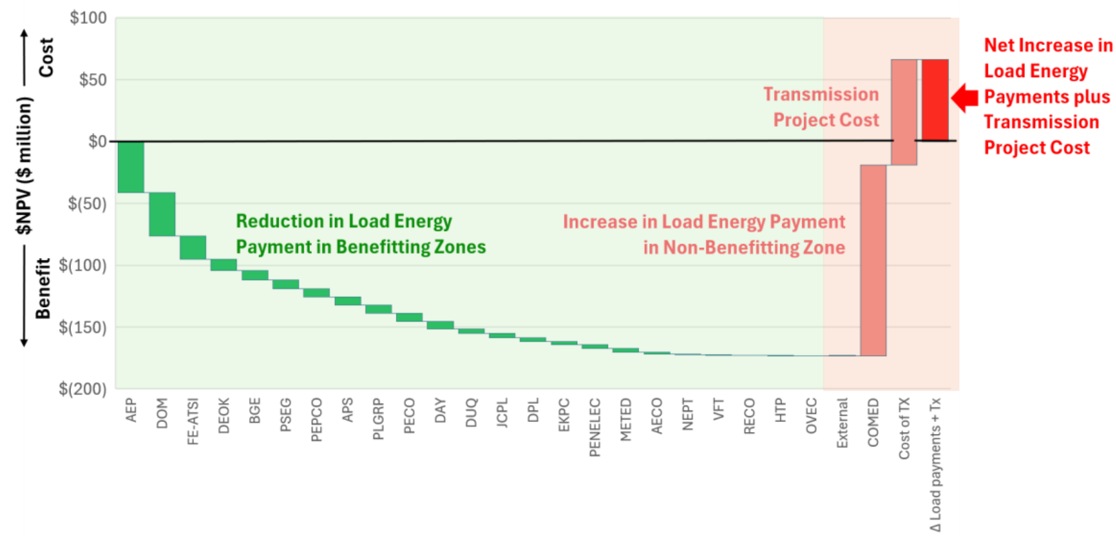
A39. My proposed replacement rate will not eliminate market efficiency projects in PJM. For lower voltage projects (where the benefit formula is based entirely on consumer costs), my proposed replacement rate would only eliminate projects that would make consumers in aggregate worse off due to the combination of energy, capacity, and transmission costs. For regional projects (where the benefit formula weighs consumer and societal costs each at 50%), my proposed replacement rate would impede projects that would make consumers in aggregate worse off but not entirely eliminate these projects due to the consideration of societal benefits. In both cases, my remedy ensures that the consumer component of PJM's benefit calculation appropriately reflects the impact on all PJM consumers. Projects that reduce consumer costs for all PJM consumers would not be impacted.

Q40. WOULD RECENT MARKET EFFICIENCY PROJECTS BE IMPACTED BY YOUR PROPOSED CHANGE?

A40. I received data from PJM and reviewed three recent candidate market efficiency projects that PJM evaluated in its recent Regional Transmission Expansion Planning (RTEP) process. Of those, only one would have had a different approval outcome under my proposed remedy.

Specifically, I analyzed the Goalders Creek substation expansion, Museville-Smith Mountain upgrade, and the Multi-Driver project in the COMED-NIPSCO-AEP area. These are RTEP proposals 525, 733, and 644+908, respectively.[38] Of these three, the only impacted proposal would be 644+908 (the Multi-Driver project in the COMED-NIPSCO-AEP area). As the graph below shows, the cost to the non-benefitting zone (COMED) is nearly as large as the aggregate benefits to all benefitting zones, and once the cost of the transmission project itself is included this project results in a $66 million net present value cost in aggregate on all PJM consumers.

Figure 4: Costs and Benefits of COMED-NIPSCO-AEP Multi-Driver Transmission Project



This analysis shows that every zone except COMED would experience a benefit (i.e. decrease in load payment), totaling approximately $170 million; while COMED customers would experience a cost increase of around $150 million. The aggregate load payment benefits to all zones are thus approximately $20 million,

[38] https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230110/item-05---2022-multi-driver-proposal-window-no-1-update.pdf; https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-03---market-efficiency-update.pdf PJM Transmission Expansion Advisory Committee, 2022 Multi-Driver Proposal Window No. 1 Update (Jan. 10, 2023), available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230110/item-05---2022-multi-driver-proposal-window-no-1-update.pdf; PJM Transmission Expansion Advisory Committee, Market Efficiency Update (Dec. 8, 2025), available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-03---market-efficiency-update.pdf.

which is significantly less than the $85.5 million transmission project cost. This finding that the costs of this transmission project outweigh the benefits is consistent with the IMM's assessment of this project as I previously quoted.[39]

Based on my analysis here, I reach the same conclusion as the IMM did: this project should have been rejected, because after accounting for the impact to *all* customers (including those harmed in COMED), the costs of the projects outweigh the benefits.

[39] "*Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/cost ratio is 0.24, not 1.99.*" Monitoring Analytics, "2024 State of the Market Report for PJM", 2024 State of the Market Report for PJM, page 715. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf

Long-Term Considerations

Q41. ARE THERE OTHER FACTORS THAT YOU WOULD RECOMMEND THAT FERC CONSIDER IN SETTING POLICY FOR HOW PJM EVALUATES MARKET EFFICIENCY PROJECTS?

A41. Beyond the immediate remedy that I propose to rectify the unjust and unreasonable flaw of the current PJM methodology, FERC should also consider more structural changes to the framework that relate to long-term economic efficiency.

Q42. PLEASE DESCRIBE THE CONCEPT OF "ECONOMIC EFFICIENCY" AS IT RELATES TO TRANSMISSION.

A42. "Economic efficiency" is a general concept in economics that refers to maximizing societal value, or equivalently, minimizing societal costs. Notably, a framework that evaluates economic efficiency captures impacts to all members of society: producers and consumers.

As I describe above in the Background section, a common approach to valuing market efficiency transmission projects quantifies the "societal" value of how much a transmission project can decrease energy dispatch costs and installed capacity costs. If the transmission project costs less than the societal benefits it creates, it is economically efficient.

Because the societal benefits of transmission can differ from how consumer prices change, any framework values transmission using consumer price benefits has the potential to over or undervalue transmission relative to its societal value. When transmission projects are overvalued relative to their societal value, this can lead to transmission investments that are economically inefficient, meaning they increase societal costs. When transmission projects are undervalued relative to their societal value, this can lead to transmission projects not moving forward that have the potential to decrease societal costs.

Q43. DOES PJM'S METHOD THAT USES CONSUMER BENEFITS RESULT IN PROJECTS THAT ARE ECONOMICALLY INEFFICIENT?

A43. PJM's methodology can approve economically inefficient transmission projects because it does not use societal benefits as the sole metric for quantifying the benefits of market efficiency projects. Since societal value provides the economic basis for efficiency, PJM's approach can (ironically) yield market efficiency transmission projects that are not efficient.

Q44. CAN YOU PROVIDE AN EXAMPLE OF USING SOCIETAL BENEFITS FROM ANOTHER JURISDICTION?

A44. Yes, MISO's methodology is a good counterexample. MISO evaluates economic transmission projects through its annual MISO Transmission Expansion Plan ("MTEP") process. Projects intended primarily to address economic needs are designated Market Efficiency Projects ("MEPs"). To qualify, an MEP must satisfy a minimum regional benefit-to-cost ratio of 1.25-to-1 using the benefit metrics specified in Attachment FF-7 of the MISO Tariff. Benefits are evaluated over a long-term planning horizon of up to 20 years.[40]

[40] Midcontinent Independent System Operator ("MISO"), Open Access Transmission, Energy and Operating Reserve Markets Tariff; Transmission Expansion Planning Protocol: https://docs.misoenergy.org/miso12-legalcontent/Attachment_FF_-_Transmission_Expansion_Planning_Protocol.pdf, pages 40 – 43 and 513 – 518 (pdf).

The principal benefit metric is Adjusted Production Cost ("APC") savings, which measures the reduction in total generation production costs across the MISO footprint resulting from the project. APC savings are distinct from changes in load energy payments, which reflect market settlement outcomes rather than changes in underlying production costs. In addition to APC savings, MISO's tariff recognizes other benefit categories, including avoided reliability project costs and certain MISO-SPP settlement-related impacts, where applicable.

Importantly, APC benefits are calculated on a footprint-wide basis: in computing the net benefits of a project, MISO sums APC savings across all zones, whether a given zone's APC savings are positive or negative.[41] Zones experiencing increased production costs resulting from a project remain part of the analysis when net benefits are determined. Only after the economic evaluation is complete does MISO turn to cost allocation, where it looks solely to benefiting zones, allocating MEP costs only to zones that exhibit a net positive present value of benefits over the evaluation period.[42]

Q45. WHY DOES PJM USE CONSUMER BENEFITS INSTEAD OF SOCIETAL BENEFITS FOR VALUING MARKET EFFICIENCY TRANSMISSION PROJECTS?

A45. The decision to use societal benefits (that promote economic efficiency) vs. consumer benefits is ultimately a policy decision. In many cases, the decision to

[41] MISO, Economic Planning Whitepaper, MISO Economic Planning Whitepaper651689.pdf, 2024, page 23 (pdf).
[42] MISO, Transmission Planning Business Practices Manual, BPM-020-r33: https://cdn.misoenergy.org/BPM-020%20Transmission%20Planning113822.zip, page 167 (pdf).

use consumer benefits is based on the motivation to minimize consumer costs, without regard for the welfare of generators.

However, planning transmission that just focuses on consumer costs without regard for the welfare of generators can actually have the unintended long-run impact of *increasing* consumer costs. This is because this framework can create a less attractive investment environment for generators. If a prospective generator knows that the RTO will plan transmission with the goal of reducing market prices, it may internalize this as a form of "regulatory risk" that subsequently increases its cost of capital (entry). In the long-run, these higher investment costs will be passed on to consumers, counter-acting the premise of planning transmission to their benefit in the first place. For example, prominent energy economist Dr. Steven Stoft remarks that:

> *Investors take account of the cost of expropriations by factoring that possibility into future investment decisions. This demonstration effect will not be confined to the load pocket in question. It is impossible to predict what the cost of this will be, but the resulting investment risk premiums will affect the rate of return on all capital in the affected load pockets, not just the new investment. This is a consequence of a market-clearing electricity price. Probably the most sensible guess is that all of the money transferred to load from existing generators will be lost to load through higher risk premiums. In conclusion, it is inefficient to eliminate all congestion, and it is wrong to focus on short-run consumer cost reductions when planning transmission investments. As with any type of productive investment, the goal should be to minimize the total cost of production and delivery. If the market is competitive or the regulation effective, these costs savings will be passed through to consumers.*[43]

For this reason, economists often advocate for using societal benefits to value transmission, because it makes the RTO a neutral party ("benevolent

[43] Transmission Investment in a Deregulated Power Market, Steven Stoft, Chapter 4 in Competitive Electricity Markets and Sustainability, 2006, page 6.

planner") with respect to market participants, rather than a quasi-consumer-advocate who plans the system in their specific interest.[44]

Q46. IN LIGHT OF THIS OBSERVATION, ARE THERE BROADER CHANGES TO PJM'S MARKET EFFICIENCY PROJECT-SELECTION FRAMEWORK THAT MAY WARRANT CONSIDERATION IN THE FUTURE?

A46. Yes. While my proposed replacement rate does not recommend that PJM adopt the use of societal benefits to value market efficiency transmission projects, this is an option that PJM could consider in the future.

There are two ways that PJM could more directly consider societal benefits of transmission. First, PJM could simply use societal benefits as the sole benefit metric for valuing market efficiency transmission projects. Such an approach would simply apply 100% weight to the production cost savings portion of the energy market benefit and capacity market benefit, without separate weight or consideration for changes in load customer payments. Another approach would use societal costs as part of a two-part test. For example, PJM could require that a candidate market efficiency project must be cost effective using both societal

[44] https://www.analysisgroup.com/globalassets/insights/publishing/blue_ribbon_panel_final_report.pdf. See pages 17 to 20. They specifically describe one of the fundamental principles of planning and cost allocation as follows:

> "An appropriate standard of measurement of the benefits of transmission is aggregate societal benefits within the geographic region or market being examined. This is the same concept that economists use when they describe "social welfare." It focuses on the question of whether a particular upgrade or set of transmission enhancements provide net positive benefits to the system being analyzed. It does not focus on who, within that system, benefits or loses from a particular investment. (Economists call these "distributional" impacts, or economic transfers from one group to another within the system being analyzed.) Certainly, economic transfers (including energy price effects pre- and post-introduction of a new transmission element in the system) can be considered as part of the analysis guiding allocation of costs, but these should be secondary to considerations of whether there are net benefits if the project is built in the first place."

benefits *and* consumer benefits. This approach would ensure that PJM does not build economically inefficient transmission (due to the societal benefits screen) or transmission that increases consumer costs (due to the consumer benefits screen).

Q47. WHY DO YOU NOT INCLUDE EITHER OF THESE AS RECOMMENDATIONS IN YOUR PROPOSED REPLACEMENT RATE?

A47. These broader policy design choices, while important for PJM to consider, are distinct from the narrower defect of discriminatory treatment between PJM consumers addressed in this testimony.

5. Recommendations & Summary

Q48. IN LIGHT OF THE ARGUMENTS YOU MAKE, DO YOU HAVE A RECOMMENDATION?

A48. Yes. I recommend that FERC order PJM to consider the economic impact to all zones (benefitting and non-benefitting) when calculating aggregate consumer benefits for market efficiency transmission projects.

Q49. PLEASE SUMMARIZE YOUR TESTIMONY.

A49. Yes. The key takeaways of my testimony are:

- PJM evaluates "market efficiency" transmission projects designed to improve system economics by allowing the lowest cost generation to dispatch through reduced congestion;
- In valuing the consumer benefits of candidate market efficiency transmission projects, PJM only includes the impacts to consumers that experience a net benefit and exclude the impact to consumers that experience a net cost;
- This unjust differentiation between different consumers in PJM is discriminatory, and PJM's methodology is therefore unjust and unreasonable;
- The result of this discrimination is market efficiency projects that overvalue transmission and can increase aggregate consumer electricity costs in PJM;
- To rectify the unjust and unreasonableness of PJM's current framework, PJM should simply include the economic impact of all zones (benefitting

and non-benefitting) when calculating consumer benefits. This approach will ensure non-discriminatory treatment between all PJM consumers and ensure that PJM does not build market efficiency transmission projects that increase aggregate consumer electricity costs in PJM; and

- In the longer-term, PJM could also consider more structural changes to valuing the benefits of market efficiency projects that focuses more on societal benefits and less on consumer benefits.

Q50. DOES THIS CONCLUDE YOUR TESTIMONY?

A50. Yes.

Appendix: Jurisdictional Review

Jurisdictional Review of Select Transmission Project Economic Evaluation Frameworks in North America

This appendix reviews how other major ISOs and RTOs in North America evaluate economic transmission projects, which are analogous to PJM's "Market Efficiency" project category. The review focuses specifically on two dimensions that are central to this testimony: (1) the benefit metric used, and (2) the zones included in the benefit calculation. This jurisdictional review is summarized in Table 5 below.

Table 5: Summary of Transmission Economic Evaluation Frameworks in North America

ISO/RTO	Program and Project Type	Benefit Metric	Zones Included
PJM (current)	**Program:** Regional Transmission Expansion Plan (RTEP) **Project Type:** Market Efficiency Projects	**Lower Voltage: Consumer** Load energy and capacity payments **Regional: Hybrid of societal and consumer** 50% Production and capacity cost savings and 50% load energy and capacity payments	**Consumer: Benefitting zones only** **Societal: All zones**
MISO	**Program:** MISO Transmission Expansion Plan (MTEP) **Project Type:** Market Efficiency Projects	**Societal** Production cost savings, avoided reliability project costs	**All zones**
SPP	**Program:** Integrated Transmission Plan (ITP) **Project Type:** Economic Projects	**Societal** Production cost savings (termed Adjusted Production Cost), any other quantifiable benefit	**All zones**
NYISO	**Program:** Comprehensive System Planning Process (CSPP) **Project Type:** Regulated Economic Transmission Projects (RETP)	**Societal** Production cost test required first	**All zones**
ISO-NE	**Program:** System Efficiency Needs Assessment (SENA) **Project Type:** System Efficiency Transmission Upgrades (SETUs)	**Societal** Production cost savings, avoided transmission losses, avoided future transmission investment	**All zones**
CAISO	**Program:** Transmission Planning Process (TPP) **Project Type:** Economic Projects	**Consumer** Load energy payment that excludes generator impacts	**All zones**
ERCOT	**Program:** Regional Transmission Plan (RTP) **Project Type:** Economic Transmission Projects	**Both societal and consumer** Production cost savings (societal) or load energy cost (consumer); project passes if either test passes	**All zones**
AESO	**Program:** Optimal Transmission Planning (OTP) **Project Type:** Economic Projects (effective 2027)	**Societal** Production cost savings, avoided capacity costs, and avoided reliability project costs	**All zones**

MISO

Planning Program

MISO evaluates economic transmission projects through its annual MISO Transmission Expansion Plan (“MTEP”). The MTEP is a non-siloed planning process that considers reliability, economic, and policy needs together across a range of future scenarios. Projects that address primarily economic needs are designated Market Efficiency Projects (“MEPs”). Projects that address a combination of economic, reliability, and policy needs are designated Multi-Value Projects (“MVPs”). This appendix focuses on the MEP category, which is most analogous to PJM's Market Efficiency projects.

Study Horizon & Methodology

Benefits are evaluated over a long-term horizon of up to 20 years. MISO uses multiple future scenarios to account for uncertainty in load growth, fuel prices, and generation mix. The analysis uses capacity expansion modeling to identify the resource portfolio in each scenario, followed by production cost modeling to quantify dispatch savings.

Benefit Metric

MISO uses a societal benefit metric. The primary benefit measure is production cost savings, which is the reduction in the total cost of generating electricity across the footprint, calculated by comparing dispatch costs with and without the candidate project. Production cost savings are different than changes in load energy payments; the two measure different things and cannot be combined.

Zone Inclusion

Benefits are calculated across all zones in the MISO footprint. Zones that experience higher production costs as a result of the project are included in the analysis and their negative impacts are not excluded from the benefit calculation. The distribution of production cost savings across zones does inform cost allocation: zones that experience a net cost increase are not required to pay for MEPs, while all customers share the cost of MVPs.

SPP

Planning Program

SPP evaluates economic transmission needs through its annual Integrated Transmission Plan (“ITP”). The ITP assesses reliability, economic, and policy needs in parallel. For economic needs, SPP identifies transmission constraints that create significant, recurring congestion costs and evaluates candidate projects to relieve those constraints. Candidate projects must demonstrate cost-effectiveness over both a near-term and a long-term horizon to be included in the final portfolio of recommended projects.

Study Horizon & Methodology

SPP evaluates benefits in select study years: years 2, 5, and 10 of the planning horizon. Results are linearly interpolated between study years and extended out to a 40-year horizon. The analysis uses up to three futures to account for uncertainty in key variables such as load growth and generation mix.

Benefit Metric

SPP uses a societal benefit metric. The primary measured benefit is the reduction in total production costs, known as Adjusted Production Cost ("APC") savings, calculated across all SPP pricing zones. The "adjustment" refers to accounting for purchases and sales of energy with other balancing authorities. SPP may also consider other quantifiable benefits where data supports them, though additional benefit categories are not enumerated with the same specificity as in MISO. Capacity cost savings are not a separately identified benefit category in SPP's economic project evaluation framework.

Zone Inclusion

APC savings are calculated across all SPP pricing zones. Zones that experience higher costs as a result of a candidate project are not excluded from the calculation. The benefit reflects the net system-wide change in dispatch costs.

NYISO

Planning Program

NYISO evaluates economic transmission needs through the Congestion Assessment and Resource Integration Study ("CARIS"), the economic planning component of its Comprehensive System Planning Process ("CSPP"). CARIS identifies and ranks congested transmission elements across a 10-year planning period and evaluates the cost-effectiveness of generic solutions, including transmission, generation, demand response, and energy efficiency, using the Production Cost Savings Test as the primary benefit metric. When CARIS identifies a cost-effective need, developers may propose specific projects to address it.

Study Horizon & Methodology

The CARIS study is conducted using a forward-looking production cost model over a multi-year planning window. NYISO does not specify a fixed study horizon for economic projects in the same way as other ISOs reviewed here.

Benefit Metric

NYISO uses a societal benefit metric for its primary economic evaluation. The Production Cost Savings Test is the key metric used in CARIS: it measures the system-wide reduction in dispatch costs that would result from addressing identified congestion and is the basis on which NYISO evaluates and ranks generic solutions. NYISO also calculates a system-wide Gross Load Cost metric, which measures the change in total consumer energy payments, but this is used for informational purposes only and does not determine whether a solution advances.

Only after a solution is identified as cost-effective through CARIS does NYISO proceed to the separate RETP cost recovery process. In this step, a proposed project must demonstrate that the sum of zonal load savings in benefitting zones exceeds the project's revenue requirement, and an 80% supermajority of beneficiary load must vote to proceed before regulated cost recovery is granted.

Zone Inclusion

All zones are included in the CARIS region-wide production cost test, including those that experience cost increases. Zones harmed by a project are not excluded from the benefit calculation; their negative impacts reduce the measured net benefit and can cause a project to fail the test.

The RETP cost recovery eligibility determination considers only zones with net load savings, for the purpose of assessing whether sufficient beneficiary support exists for regulated cost recovery. Zones harmed by a project bear none of the costs and have no vote, but their welfare is fully reflected in the CARIS economic evaluation that precedes the cost recovery process.

ISO-NE

Planning Program

ISO-NE evaluates economic transmission needs through its System Efficiency Needs Assessment ("SENA"), governed by Section 17 of Attachment K of the Open Access Transmission Tariff. Projects that address economic needs are designated System Efficiency Transmission Upgrades ("SETUs"), formerly called Market Efficiency Transmission Upgrades ("METUs"). ISO-NE identifies congested transmission elements and evaluates candidate upgrades through a competitive request for proposal ("RFP") process when annual congestion costs exceed the tariff threshold (currently $4.3 million per year).

Study Horizon & Methodology

ISO-NE evaluates candidate upgrades over a 10-year planning horizon using a two-pass production cost model. For each candidate transmission project, ISO-NE compares production costs for the region with and without the proposed upgrade. A single study year, corresponding to the last year of the 10-year horizon, is used as the basis for the benefit calculation. Results are converted to a present value for comparison against project costs.

Benefit Metric

ISO-NE uses a societal benefit metric. The primary benefit measure is production cost savings across the full New England system and the surrounding NPCC region. In addition to production cost savings, ISO-NE includes two supplemental benefit categories: avoided transmission losses (the reduction in energy wasted in transmission as a result of the upgrade) and avoided future transmission investment (the cost of other planned transmission upgrades that are no longer needed because of the candidate project). Capacity cost savings are not a separate benefit category in ISO-NE's economic project evaluation framework.

Zone Inclusion

Production cost savings are calculated on a system-wide basis across all New England load zones. No zone is excluded from the analysis on the basis that it experiences a cost increase as a result of the candidate project. Cost allocation for approved SETUs follows a load-ratio basis across the full region, consistent with ISO-NE's principle that all consumers benefit from improvements to the interconnected regional network.

CAISO

Planning Program

CAISO evaluates economic transmission needs through its annual Transmission Planning Process ("TPP"), which addresses reliability, policy, and economic needs in an integrated planning cycle approved by the CAISO Board of Governors. Within the TPP, economic needs are identified through Economic Planning Studies that assess congestion and evaluate candidate projects.

Study Horizon & Methodology

CAISO conducts production cost studies for two study years: 5 years and 10 years after the project in-service date. Benefits for the years between the 5-year and 10-year studies are estimated through linear interpolation. Beyond 10 years, benefits are held constant at the 10-year value. Net present values are then calculated over the expected lifetime of the project. CAISO also evaluates sensitivity scenarios by varying key assumptions such as load growth, fuel prices, and hydro conditions, depending on data availability for the specific project.

Benefit Metric

CAISO uses a consumer benefit metric for planning purposes, assessed through the Transmission Economic Assessment Methodology ("TEAM"), which CAISO has used since 2004. Although TEAM was originally designed to assess multiple perspectives including a full societal one, CAISO has in practice relied on the ratepayer perspective, which measures the net change in what electricity consumers pay and excludes the welfare of merchant generators. The rationale is that ratepayers bear the cost of transmission investment and their welfare is therefore the relevant measure for planning decisions. For inter-regional projects with impacts extending beyond the CAISO footprint, CAISO also considers a broader regional societal perspective.

Zone Inclusion

Although CAISO uses a consumer benefit metric rather than a societal one, it does not discriminate among ratepayers based on whether they benefit from a project. The ratepayer benefit calculation reflects the net change in consumer costs across all pricing zones in the CAISO footprint, including zones that experience higher costs. No zone is excluded from the calculation because it experiences a cost increase.

ERCOT

Planning Program

ERCOT evaluates economic transmission needs through its annual Regional Transmission Plan ("RTP"). The RTP addresses both reliability and economic needs. Economic analysis is conducted for select future study years within the planning horizon. Candidate projects are identified based on their potential to address significant, recurring congestion, and benefits and costs are compared on a present-value basis.

Study Horizon & Methodology

ERCOT evaluates benefits in select future study years chosen to represent a range of plausible system conditions. Results for each study year are levelized and discounted to a present value over the expected life of the project.

Benefit Metric

ERCOT uses a dual-test framework: it calculates both system-wide production cost savings and system-wide consumer energy cost savings. Capacity cost savings are not a separate benefit category in either test. A project is recommended if it passes *either* test. The rationale for including the consumer energy cost test alongside the production cost test is that load bears 100% of transmission costs in ERCOT, giving consumer impacts particular weight in planning decisions. Including the production cost test alongside the consumer test ensures that projects that only transfer wealth from generators to consumers, without creating system-wide efficiency gains, still face scrutiny.

Zone Inclusion

Both the production cost test and the consumer cost test are calculated on a system-wide basis across all ERCOT zones. Neither test excludes zones that experience cost increases as a result of the project. The net system-wide change is used in both cases.

AESO

Planning Program

The Alberta Electric System Operator ("AESO") is transitioning to a new Optimal Transmission Planning ("OTP") framework, effective in 2027. Historically, Alberta operated under a planning standard that required the near-elimination of transmission congestion regardless of cost. The OTP framework replaces this with an economic planning standard that requires the AESO to weigh the benefits of transmission expansion against its costs, in recognition that some congestion is efficient when the cost of relieving it exceeds the benefits of doing so.

Study Horizon & Methodology

Under the OTP framework, benefits will be evaluated over a long-term planning horizon using multiple future scenarios, consistent with a least-regrets planning approach. The analysis will draw on capacity expansion modeling to determine the evolving resource mix and production cost modeling to quantify dispatch savings. The specific study years and scenario methodology are still being finalized as part of the 2027 implementation.

Benefit Metric

The OTP framework uses a societal benefit metric. Benefit categories include production cost savings, avoided capacity costs, and avoided reliability project costs, which are consistent with the benefit categories used by MISO. The framework is designed as a total-surplus analysis that does not prioritize the welfare of any particular class of market participant. The specific weighting and methodology for combining these benefit categories are still being finalized as part of the 2027 implementation.

Zone Inclusion

Benefits are assessed across the entire Alberta footprint. No zone or class of market participant is excluded from the analysis or given preferential weight. The framework does not differentiate between benefitting and non-benefitting zones for purposes of the benefit-cost determination.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pennsylvania Public Utility Commission	)	
Complainant,	)	Docket No. EL26-___-000
	)	
v.	)	
	)	
PJM Interconnection, LLC,	)	
Respondent	)	

CERTIFICATE OF ZACHARY MING

I, Zachary Ming, declare under penalty of perjury that I am the author of the foregoing testimony, that the facts set forth herein are true and correct to the best of my knowledge, and that if asked the same questions contained in the text, I would give the answers contained in the testimony.

/s/ Zachary Ming________ August 17, 2026__

Zachary Ming Dated

ATTACHMENT B

Zach Ming

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Partner

Mr. Ming leads E3's market design practice, with an emphasis on electricity systems operating under higher penetrations of renewable energy. He also has extensive expertise in resource planning, reliability and resource adequacy, regulatory and rate design issues, and distributed resource cost effectiveness. Recent projects include testifying before the Puerto Rico Energy Bureau on the topic of cost allocation and rate design, testifying before the Public Service Commission of South Carolina on PURPA rates, and testifying before the New Brunswick Energy & Utilities Board on cost allocation. Mr. Ming has also authored white papers for the Regulatory Assistance Project on rate design and worked with utilities to develop innovative new rates such as wholesale rates to facilitate flexible green hydrogen customers in Nova Scotia. Mr. Ming has testified before FERC on six different topics and has testified before regulators in Texas, Colorado, Oregon, South Carolina, New Brunswick, and Puerto Rico. Mr. Ming has been the lead author on several high-profile resource planning studies including *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California* and *Resource Adequacy in the Pacific Northwest*.

Mr. Ming teaches a graduate level course at Stanford University titled *Electricity Economics* that provides a foundation of economic principles on the topics of regulation, planning, and operation of electric utilities, with a particular emphasis on emerging electricity sector topics such as renewable energy, energy storage, distributed resources, and market design. Mr. Ming holds an M.S. in management science and engineering (energy and environment track) and a B.S. in civil and environmental engineering (atmosphere and energy) from Stanford University.

Select projects at E3 include:

- **Puerto Rico Energy Bureau, Cost of Service and Rate Design Expert Support, 2025:** Mr. Ming wrote and submitted an expert report to the Puerto Rico Energy Bureau on cost allocation and rate design, advising the Bureau on these topics in support of LUMA's 2025 rate case — the first such proceeding since 2015. E3 supported the Bureau and Hearing Examiner, serving as lead expert on cost allocation, revenue allocation, and rate design, including evaluating LUMA and stakeholder filings and developing background training materials for the Bureau.
- **PJM Transmission Tariff, Constellation, 2025:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on the co-location of loads with generators in PJM. The testimony identifies three configurations of co-located loads (firm, generator-contingent, and interruptible) each uniquely impacting transmission costs and reliability. The testimony proposes targeted tariff structures that align with rate design principles.
- **Transmission Rate Design Analysis, AltaLink, 2017-2021:** Mr. Ming conducted rate design and regulatory analysis on the existing wholesale transmission tariff in Alberta and proposed alternative designs that were more aligned with cost-of-service principles.
- **Reliability Risk Model Assessment, PJM, 2021-2025:** Mr. Ming led a team that provided a detailed technical review of the probabilistic reliability risk model used by PJM to calculate capacity requirements and resource accreditation values (including renewables, storage, and thermal) for use in

the PJM capacity market. Elements of the model that were reviewed include data inputs, assumptions, algorithms, methods of use, and results. Through this process, E3 made multiple suggestions for improvement to PJM staff.

- **PJM Marginal Effective Load Carrying Capability Testimony, Calpine, 2023:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission supporting PJM's proposal to accredit the capacity of resources in the capacity market using a marginal effective load carrying capability (marginal ELCC methodology). Mr. Ming argued that this approach would 1) ensure reliability 2) provide economically efficient signals for entry and exit 3) was fair and technology-neutral and 4) was simple and acceptable.
- **PJM Capacity Market Price Cap Testimony, Calpine, 2025:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on the appropriate price cap in the PJM capacity market. Mr. Ming argued that a reduced price cap would hinder the ability of the market to deliver long-term reliability goals. In subsequent testimony, Mr. Ming argued that any reduction in price cap should be accompanied by an increase in the price floor, a settlement that was ultimately adopted.
- **PJM Reliability Must Run Testimony, Calpine, 2024:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on the participation of reliability must run ("RMR") units in the PJM capacity market. Mr. Ming argued that units receiving out-of-market payments should not participate in the capacity market due to the price suppression effects on other generators.
- **ISO-NE Pay-for-Performance Testimony, NEPGA 2025:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on behalf of the New England Power Generators Association (NEPGA) on the pay-for-performance pricing mechanism in the ISO-NE capacity market. Mr. Ming argued that the existing mechanism that allowed fully performing units to be penalized during certain scarcity events was unjust and unreasonable and proposed an alternative framework that rectified this shortcoming.
- **Xcel Colorado Resource Adequacy Study and Testimony, 2025:** Mr. Ming performed a study for Xcel Colorado to calculate the required planning reserve margin (PRM) and resource effective load carrying capability (ELCC) values for the utility. Mr. Ming testified before the Colorado Public Utilities Commission on this study.
- **New Brunswick Power Cost Allocation Study, 2023:** Mr. Ming developed a model to analyze allocation of costs to customer classes using four different cost allocation methodologies: average and peak, average and peak with time-of-use, probability of dispatch, and marginal cost. Mr. Ming testified as an expert before the New Brunswick Energy and Utilities Board, participated in oral hearings, and was cross examined by intervening stakeholders.
- **PURPA Expert Witness Testimony, South Carolina Office of Regulatory Staff, 2023:** Mr. Ming reviewed Public Utilities and Regulatory Policy Act (PURPA) filings submitted by South Carolina's investor-owned utilities on behalf of the Office of Regulatory Staff. Mr. Ming reviewed for adherence to rate design best practices and application of avoided cost principles for both energy, capacity, and renewable integration costs. Mr. Ming testified before the South Carolina Public Service Commission to provide an overall assessment as well as recommendations for improvement.
- **Market Design Reform Analysis, Public Utility Commission of Texas, 2022-2023:** Mr. Ming led analysis to evaluate the portfolio, reliability, and cost impacts of various market design reform proposals being contemplated in the ERCOT market. E3 published these findings in a report, and Mr. Ming publicly presented these results before the Commissioners at an open meeting and to state legislators.[45]
- **Net Zero New England, Calpine, 2020:** Mr. Ming advised on a comprehensive economy-wide decarbonization analysis with a specific focus on the electricity sector. The analysis focused on the

[45] https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=2

operating challenges at higher penetrations of renewables and the role of firm generation in the New England ISO under a net-zero carbon target.[46]

- **ISONE Capacity Market Design, Confidential Client, 2022:** Mr. Ming, on behalf of a confidential client, presented recommendations to the New England ISO (ISONE) on methods and improvements to better reflect winter reliability risks, particularly due to fuel constraints, in reliability risk modeling used in their capacity market.
- **Capacity Market Design, NYISO, 2022:** Mr. Ming advised the New York ISO (NYISO) on best practices for the adoption of a marginal effective load carrying capability (ELCC) framework within their capacity market construct. In 2022, NYISO became the first ISO to receive FERC approval for the implementation of a marginal ELCC framework. E3 also advised on technical implementation details including best modeling practices to balance both accuracy and simplicity.
- **Capacity Market Design, MISO, 2023:** Mr. Ming was retained by the Midcontinent Independent System Operator (MISO) to provide expert testimony regarding MISO's filing before FERC to implement a "direct loss of load" methodology for use in their capacity market. Mr. Ming also led a team that provided advice on other topics including best practices for assessing local reliability requirements and determining which hours should be utilized in assessing reliability requirements.
- **Capacity Value, Oregon Public Utility Commission, 2020-2022:** Mr. Ming developed a best practices framework for assessing the capacity value of for use in various Commission proceedings. Mr. Ming publicly testified before Commissioners at an open meeting to present results and answer questions.
- **Santee Cooper, the State of South Carolina, 2019-2020:** Mr. Ming managed an engagement with the State of South Carolina to advise on the potential sale of Santee Cooper, a state-owned utility with significant debt due to the abandonment of the V.C. Summer nuclear units 2 & 3. Mr. Ming testified before the South Carolina legislature to present the pros and cons of a potential sale, management arrangement, or reform of the utility.
- **Offshore Wind Reliability Analysis, Confidential Client, 2022:** Mr. Ming led a team to evaluate the reliability contribution of offshore wind in the PJM market for a confidential client. The team utilized detailed renewable output profiles to calculate effective load carrying capability (ELCC) values across a number of different future years and scenarios. The analysis determined that while offshore wind could make meaningful contributions to reliability, there remained a strong role for firm resources to ensure reliability across all conditions.
- **Firm Generation in Microgrids, Mainspring Energy, 2021:** Mr. Ming developed a report for Mainspring Energy evaluating the role of firm generation in local microgrids in California. E3 evaluated several different microgrid configurations including solar + storage, solar + fuel cell, and solar + Mainspring to determine that the lifecycle economics of solar + Mainspring were superior to alternative options, while providing equivalent emission and reliability outcomes.[47]
- **Renewable Reliability Value Analysis, Lincoln Electric System, 2022:** Mr. Ming oversaw a team that calculated renewable capacity values for Lincoln Electric System (LES) within the context of the Southwest Power Pool (SPP) market. The team calculated a forecast of ELCC values for wind, solar, and battery storage, which were provided to LES for use in their 2022 integrated resource plan.[48]
- **Renewable Effective Load Carrying Capability Analysis, Salt River Project, 2022:** Mr. Ming advised on a project to calculate the renewable effective load carrying capability (ELCC) values for wind, solar, and battery storage for Salt River Project (SRP). These values were used in SRP's 2022 integrated resource plan.

[46] https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf
[47] https://www.ethree.com/wp-content/uploads/2021/03/The-Role-of-Firming-Generation-in-Microgrids-E3-and-Mainspring-Energy.pdf
[48] https://www.les.com/sites/default/files/resource-items/irp-report.pdf

- **Boulder Canyon Dam Pumped Storage Value Analysis, Los Angeles Department of Water and Power, 2019:** Mr. Ming led a team to evaluate the economics of converting Boulder Canyon Dam into a pumped storage facility to provide value integrating the increasing penetration of renewables in the Western interconnection.
- **Wholesale Market Tariffs, Nova Scotia Power, 2020-2021:** Mr. Ming developed testimony to support reforms to existing wholesale market tariffs to ensure they were consistent with best practices in competitive markets across North America.
- **Capacity Market Design, PJM, 2020-2021:** Mr. Ming provided advice to PJM on the incorporation of the effective load carrying capability (ELCC) metric into the PJM capacity market as a method to quantify the contribution of renewable energy and storage resources. Mr. Ming presented publicly the findings of the project at a PJM stakeholder workshop
- **Whitepaper Series, Regulatory Assistance Project, 2022-2023:** E3 worked with RAP to publish a series of whitepapers targeted to Chinese policymakers on topics related to energy and electricity. The whitepapers were published in English and Chinese and covered the topics of time-of-use ratemaking, integrating real-time pricing into rates, the value of long-term contracting, efficient capacity market mechanisms, the role of clean firm generation in a decarbonized electricity system, and the role of demand response and energy efficiency participation in capacity markets.
- **ERCOT Market Design, NRG, 2021:** Mr. Ming developed a whitepaper outlining a proposal to implement a load-serving entity reliability obligation (LSERO) product in the ERCOT market to both improve reliability and make the state less susceptible to scarcity pricing.[49]
- **California Hydrogen and CCS, Confidential Client, 2022:** Mr. Ming led analysis to evaluate the potential role and value of both hydrogen and carbon capture and sequestration (CCS) in California under the incentives of the Inflation Reduction Act.
- **Pathways to Net-Zero Carbon, Omaha Public Power District, 2021:** Mr. Ming led a study on behalf of OPPD to analyze pathways to net-zero carbon. The study found that significant quantities of wind, solar, and battery storage would be components of a least-cost/least-regrets resource plan, supplemented by firm resources for reliability such as natural gas or hydrogen. Mr. Ming led a series of six public stakeholder workshops to provide an opportunity for transparency and public input.
- **Long-Run Resource Adequacy under Deep Decarbonization Pathways for California, 2018-2019:** Mr. Ming authored a report analyzing the resource adequacy requirements of a high-renewable electricity system, consistent with California's long-term decarbonization goals of 80% by 2050. The report demonstrated that despite significant additions of renewable energy and storage, significant quantities of firm capacity were still needed to maintain sufficient reliability.
- **Reliability Value of Demand Response in California, CAISO, 2019-2022:** Mr. Ming led an effort to study the reliability impacts of demand response in the California electricity system using the effective load carrying capability (ELCC) methodology. The study showed that current methods overvalue the reliability value by 25-50%. Mr. Ming presented the findings publicly at multiple stakeholder workshops.
- **Resource Adequacy in the Pacific Northwest, Public Generating Pool, 2018-2019:** Mr. Ming authored a report analyzing the resource adequacy requirements of the Pacific Northwest under various low carbon electricity systems, including 100% carbon-free. This report was presented to multiple stakeholders and utilities in the region and has led to further discussions around resource adequacy coordination and planning.
- **Once-Through Cooling Retirement Analysis, Los Angeles Department of Water and Power, 2017:** Mr. Ming managed a project analyzing the reliability implications of retiring three once-through cooling natural gas power plants in the Los Angeles basin and replacing them with a combination of clean

[49] https://www.ethree.com/wp-content/uploads/2021/09/LSE-Reliability-Obligation-E3-ERCOT-Whitepaper_2021-09-29.pdf

resources including solar, storage, energy efficiency, and transmission. The results of this study were used to support the decision to retire all three plants and replace them with clean resources.

- **Planning Reserve Margin Study, Nova Scotia Power, 2019:** Mr. Ming led analysis to evaluate the required planning reserve margin (PRM) necessary to achieve a 1-day-in-10 year reliability standard in the province of Nova Scotia. The study also evaluated the contribution of several intermittent and energy-limited resources toward the PRM including solar, wind, energy storage, and demand response. This report was published publicly and formed a basis for Nova Scotia Power's 2020 integrated resource plan.
- **Integrated Resource Planning Support, Confidential Mid-Size Utility, 2018:** Mr. Ming managed a project evaluating the potential replacement of coal resources with renewable, energy storage, and natural gas resources in order to achieve decarbonization targets for a confidential mid-size utility.
- **Net Energy Metering Analysis, Various Clients, 2014-2017:** Mr. Ming performed analysis and published reports for various state utility commissions (California, Nevada, New York, South Carolina) evaluating the costs and benefits of net energy metering policies.
- **Heat Pump Analysis, New York State Energy and Research Development Authority, 2017:** Mr. Ming performed analysis on the costs and benefits of electric heat pumps to replace oil and natural gas heating in New York state as well as increase the efficiency of existing air conditioners. This work was published in a public report that led to the development of policies to incentivize heat pump adoption.
- **Resource Adequacy Program Design, Calpine, 2016:** Mr. Ming performed analysis on behalf of Calpine and presented to the California Public Utilities Commission (CPUC) to recommend the use of the effective load carrying capability (ELCC) metric in the Resource Adequacy (RA) program for wind and solar resources. The CPUC ultimately adopted this recommendation along with several market design features proposed by E3.
- **California Avoided Cost Calculator, California Public Utilities Commission, 2016-2018:** Mr. Ming led an update of the avoided cost forecast used to conduct cost and benefit analysis for demand-side programs in California, including energy efficiency, demand response, and distributed generation.
- **Title 24 Building Standard Development, California Energy Commission, 2016-2017:** Mr. Ming developed a forecast of future energy costs for the State of California used to establish building energy efficiency standards under Title 24.
- **Resource Value of Solar, Oregon Public Utilities Commission, 2016:** Mr. Ming contributed to expert testimony on the resource value of solar before the Oregon Public Utilities Commission.
- **Policy and Technology Scenario Analysis, Confidential Large U.S. Utility, 2015:** Mr. Ming modeled policy and technology-change scenarios for a large U.S utility as part of their strategy planning process.

GENERAL ELECTRIC — Schenectady, New York
Renewable Energy Development Program (REDP) Intern — Summer 2012

CITIGROUP — Houston, Texas
Commodities Summer Analyst — Summer 2011

OGE ENERGY CORP (Enogex) — Oklahoma City, Oklahoma
Capacity Management Intern — Summer 2010

MAP ROYALTY — Oklahoma City, Oklahoma
Engineering Intern — Summer 2009

Education

Stanford University — Stanford, California
M.S., Management Science and Engineering (Energy and Environment) — 2013

Stanford University — Stanford, California
B.S., Civil and Environmental Engineering (Atmosphere and Energy) — 2012
Minor in Economics