STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for approval of modifications to its Large Power Tariff – Tariff LP	U-21986

DIRECT TESTIMONY AND EXHIBITS OF BEN HAVUMAKI

ON BEHALF OF

ATTORNEY GENERAL DANA NESSEL

February 13, 2026

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DIRECT TESTIMONY OF BEN HAVUMAKI FOR MICHIGAN ATTORNEY GENERAL
CASE NO. U-21986

I. Introduction and Qualifications

Q. Please state for the record your name, position, and business address.

A. My name is Ben Havumaki. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics, Inc.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electricity industry.

Q. On whose behalf do you offer this testimony?

A. I am testifying on behalf of the Michigan Department of the Attorney General (AG).

Q. Please summarize your experience in the field of utility regulation.

A. For more than seven years, my work has focused on electric and gas utility regulatory issues, usually in the context of litigated proceedings. I provide technical analysis and

expert witness support in general rate cases, where I focus on rate design and cost allocation. I also have expertise in performance-based regulation and grid modernization. I have testified before utility regulatory commissions in Georgia, Illinois, New York, Minnesota, Maryland, Rhode Island, New Hampshire, Pennsylvania, West Virginia, New Brunswick, and Nova Scotia. I have also drafted comments and contributed to formal reports in numerous other jurisdictions in the United States and Canada. I hold a Bachelor of Arts degree in History from McGill University and a Master of Arts degree in Applied Economics from the University of Massachusetts. My resume is attached as Appendix A.

Q. Have you testified before this Commission as an expert in any other proceeding?

A. I have not testified before the Michigan Public Service Commission ("Commission").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the proposals of Indiana Michigan Power Company ("I&M" or "the Company") regarding its Large Power Tariff ("Tariff LP"). I address the risks associated with these new large loads, especially the risk of cost shifting in which incremental spending by the Company to serve this load raises other customers' rates; recommend cost analyses and rate classifications that would avoid this cost shifting, consistent with the Commission's final order in the recent Consumers Energy case concerning modifications to its General Primary Demand Rate (Case No. U-21859); and recommend specific modifications to Tariff LP to enhance customer protections and mitigate risk.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit AG-1:	Workpaper
Exhibit AG-2:	AG DR 1-13 - AG DR 1-15
Exhibit AG-3:	AG DR 2-40
Exhibit AG-4:	AG DR 2-36
Exhibit AG-5:	AG DR 1-22
Exhibit AG-6:	AG DR 1-20
Exhibit AG-7:	AG DR 2-34
Exhibit AG-8:	AG DR 1-24
Exhibit AG-9:	AG DR 1-9
Exhibit AG-10:	2025 State of the Market Report for PJM:
Exhibit AG-11:	Utility Dive. Introduction section to "PJM capacity auction clears at record $269.92/MW-day as data centers drive demand." December 18, 2025.
Exhibit AG-12:	Union of Concerned Scientists. Data Center Transmission Connection Costs Policy Brief. September 2025.
Exhibit AG-13:	Grid Lab. “The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.” September 2025, p. 4.

II. Summary

Q. Please summarize your conclusions.

A. My conclusions are as follows:

- The magnitude of infrastructure investment associated with potential new data centers taking service in I&M's territory necessitates robust safeguards to ensure that existing ratepayers are protected from the risk of stranded investments should the data center have lower usage than anticipated or leave the Company's service territory. It also necessitates re-evaluating the traditional ways that I&M would track and allocate the costs of its investments for data centers.
- I&M's proposed revisions to its Tariff LP Rate do not adequately protect other customers from the risk of reduced or departed data center load.
- I&M's proposal does not address the risk of shifting a portion of the extra cost of serving data center load to other customers – even if the load does materialize.

Q. Please summarize your recommendations.

A. I recommend that the Commission direct I&M to:

- Create a new rate class for all large load customers with maximum demands equal to or exceeding 50 MW at least as soon as part of I&M's next rate case.
- Ensure that new large load customers do not increase costs on other customers, by:
  - Separately tracking costs associated with serving large customer load, including the cost of procuring additional generation capacity and supply, inclusive of the costs of RPS compliance, and any incremental transmission and distribution facility costs.

- Directly assign the costs of serving new large load customers, including any direct connect costs, to either the large load customer class or to individual large load customers. If the Commission is inclined to permit any socialization of direct connect facilities, then it should require that the Company separately track any socialized costs, assign appropriate responsibility for these costs to large load customers at the customer class level, and monitor to ensure that there is no cost shifting resulting from this cost socialization. Such direct assignment should be implemented in tariff provisions as soon as possible, and at least as early as the time a new rate class is created for large load customers.

- File at least six cost allocation and rate design proposals as part of its next rate case, consistent with the Commission's decision in the recent Consumers Energy case (Case No. U-21859), in order to facilitate tracking of costs associated with large load customers and to prevent cost shifting:
  - One under traditional ratemaking as exemplified by I&M's current cost of service study (COSS) from its most recent rate case order including the expected full contract capacity of any new large load customer(s) on Tariff LP;
  - Same as (1), but with the inclusion of a new large load customer rate class (50 MW or greater);
  - Same as (2), but using 12CP to allocate costs instead of 4CP where 4CP is currently being utilized;
  - One under traditional ratemaking utilizing the most recently approved COSS without the large load customer(s) in service;

- One utilizing a direct assignment of costs to a new large load customer rate class, including transmission, generation, and distribution costs; and
- One utilizing a direct assignment of costs to the individual large load customer, again including transmission, generation, and distribution costs.

- Implement the following additional changes to the terms and conditions within Tariff LP applicable to large load customers with peak demands equal to or exceeding 50 MW:
  - Extend the minimum contract term to 20 years;
  - Incorporate an evergreen provision that would automatically extend the contract term by an additional sixty months if written notice to terminate is not provided within sixty months of the end of the contract term.
  - Limit the permitted reduction in contract capacity to 10 percent, pursuant to a contested case proceeding and subject to Commission approval; for any greater reduction, require either payment of a pro-rated exit fee based on the amount of the reduction, or Commission review and approval pursuant to a contested case proceeding if the Company asserts the exit fee is unnecessary;
  - Make the exit fee applicable to customers exiting during the ramp-up period, calculated using their contract capacity amount, with the understanding that customers or the Company might request exit fee mitigation (subject to review in a contested case proceeding) based on the use of capacity planning milestones during the ramp-up; require that any discretionary exit fee waiver or reduction in the exit fee amount be subject to Commission review and approval pursuant to a contested

case proceeding; include any contract extension due to the evergreen provision in the calculation of the exit fee.

- Institute penalties for customers who fail to provide sufficient notice to terminate service; and
- Require a collateral amount equal to the full value of the exit fee, which is the total Minimum Charge multiplied by the number of months remaining on the full term of the contract, to be recalculated annually.
- Require large load customers to cover their added cost of compliance with PA 235 by entering into contracts for procurement of at least 60 percent of their incremental energy requirements from renewable resources; and require large load customers seeking eligibility as an enterprise data center under MCL 205.54ee and MCL 205.94cc to meet the 90 percent clean energy procurement standard.
- Require that any reassignment of contract rights be subject to Commission review and approval pursuant to a contested case proceeding.

III. Background: I&M's Application and Data Center Expectations

Q. Please summarize I&M's application.

A. I&M is requesting approval of modifications to its Tariff LP to establish specific terms and conditions for large load customers, which the Company defines as customers with contract capacity that is greater than or equal to 50 MW or is reasonably expected to grow to exceed 50 MW at one or more aggregated premises ("large load customers").[1]

[1] I&M's Application, pp. 1-2.

Q. Why is I&M proposing these modifications?

A. I&M witness Caleb Loveman states that the modifications are necessary to address the unprecedented magnitude of potential new large load customers—which could more than double I&M's current Michigan peak load—and to establish reasonable protections for all customers given the significant transmission and generation infrastructure investments and long-term financial commitments that will be required to serve these loads.[2]

Q. How does prospective data center load compare with I&M's current system?

A. I&M's Michigan peak load is estimated to be approximately 520 MW for the 2025/2026 PJM Delivery Year, including customers that have elected electric choice service.[3] Mr. Loveman explains that a single 50 MW customer is equivalent to approximately 38,000 residential customers—approximately one-fourth of I&M's Michigan current retail customer count.[4]

Q. Please summarize the key elements of I&M's proposal for Tariff LP.

A. The Company proposes the following modifications to Tariff LP to apply to large load customers:

- A contract term of 15 years following an initial ramp period of up to 5 years;
- Minimum monthly billing requirements of 90 percent of contracted capacity for demand charges and 65 percent of actual energy usage;

[2] Direct Testimony of Caleb Loveman, p. 5.
[3] Loveman Direct, p. 6.
[4] *Id*.

- A provision allowing customers to reduce contracted capacity by up to 20 percent after the fifth year of the contract term, subject to 60-month advance written notice;
- An exit fee equal to minimum monthly charges multiplied by remaining contract months, applicable if a customer terminates service, takes service from an alternative electric supplier, or reduces capacity below 80 percent of the original contracted amount;
- Collateral requirements equal to two years of non-fuel charges, with the Company retaining discretion to adjust collateral amounts based on individual customer creditworthiness assessments;
- Application of the Company's existing facilities allowance policy to direct connection facilities, under which the Company finances interconnection costs that do not exceed two times the annual capacity power supply and delivery charge revenue anticipated from the customer; and
- Provisions addressing temporary service facilities, interconnection study costs, and assignment of contract rights.

Q. Would the Company have discretion to modify certain terms and conditions for large load customers?

A. Yes. The Company's proposal retains significant discretion for I&M to modify or waive certain provisions on a customer-specific basis. The Company would have the option to approve greater reductions in contract capacity, to reduce exit fees, to adjust collateral

requirements based on individual credit assessments, and to determine whether to approve assignment of contract rights.[5]

Q. What are your concerns with the Company's Tariff LP proposal?

A. The Company's proposal does not adequately guard against cost shifting. The contract term is too short, its provisions are too flexible, and the exit fee would not necessarily prevent stranded assets. Additionally, I am concerned about a lack of penalties and insufficient positive inducements to transparency and coordination between Large Load Customers and the Company, which could result in Large Load Customers transferring risk onto other customers. Finally, I observe that the Company would be afforded excessive discretion under its proposal.

IV. New Large Load Customers are Costly and Risky to Serve

Q. What does the Company say about the costs of serving new large load customers?

A. Mr. Loveman states that serving these customers will "require the Company to make significant transmission and generation infrastructure investments and other long-term financial commitments to provide service."[6]

Q. Does the Company provide any estimates of the actual costs of the generation investments that will be required to serve new large load customers?

A. The Company discusses the generation capacity costs to serve a hypothetical 50 MW customer. The Company states, "[a]t this level of potential new load, I&M expects to need

[5] *Id*.
[6] *Id*., p. 5.

to make significant financial commitments to secure new generation resources. As an illustrative example, at an average accredited capacity value of 50% and an average resource cost of $2,000/kW, it would require a generation investment of approximately $200 million to serve a 50 MW load..."[7,8]

Q. Does the Company estimate the costs of transmission or distribution upgrades?

A. No. The Company has not provided any estimates of the incremental costs of transmission and distribution facilities for large load customers. While the Company remarks on the significant scale of transmission upgrades that will be required,[9] little is said about distribution infrastructure. It is not clear whether there will be any large load customers taking service at distribution voltage, since the Company has yet to enter into any agreements with large load customers in its Michigan service territory.[10]

Q. Has the Company addressed the cost of direct connection facilities?

A. For direct connect facilities, including both transmission and distribution voltage facilities, the Company would apply its existing Contribution in Aid of Construction (CIAC) policy applicable to all commercial and industrial customers. Under this policy, the Company finances construction costs necessary to extend facilities to serve customers when such investment does not exceed two times the annual capacity power supply and delivery charge revenue anticipated to be collected from the customer.[11] Because these large load

[7] *Id*., p. 7.
[8] In response to AG DR 1-13a-b, the Company explains that the $2,000/kW figure is the average for "a diversified set of resource types with different costs, such as nuclear, gas, solar, and wind." Exhibit AG-2.
[9] Loveman Direct, p. 7.
[10] Exhibit AG-3, Response to AG DR 2-40.
[11] Exhibit AG-4, Response to AG DR 2-36 (also referencing page C-12.00 of the Company's Michigan ratebook).

customers are so large, the magnitude of this investment would be significantly higher than typically incurred by the Company to serve new customers. Thus, the Company's policy would allow for the socialization of costly interconnection facilities for large load customers, potentially allowing hundreds of millions of dollars in interconnection costs to be financed by the Company and recovered from all ratepayers.[12,13]

Q. How would the Company allocate the incremental generation, transmission, and distribution costs associated with serving new large load customers?

A. The Company proposes to follow its standard cost allocation practices for allocating costs associated with new large load customers. In other words, these costs would be pooled with the other shared system costs and then allocated according to existing methods. Specifically, generation capacity costs would be allocated using the traditional 4CP approach.[14] Local and regional transmission costs would be allocated per the PJM tariff,[15] while the costs of customer direct connections (both distribution and transmission) would be at least partially socialized to all customers.[16]

Q. Could the Company's approach to allocating the incremental costs of serving new large loads raise rates for all customers?

[12] In the recent Consumers case (U-21859), Consumers Energy estimated that the cost of interconnecting a 100 MW customer would range from $46.5 million to $96 million. The utility indicated the following cost breakdown: $28 million to $34 million for distribution costs, consisting of an average transformer cost multiplied by the estimated number of transformers required to serve the customer; $18.5 million to $62 million in estimated transmission costs. *See*, AG Brief in Case No. U-21859, p. 14-15.

[13] When asked in discovery to produce estimates for distribution interconnection costs, such as additional transformer substations, I&M objected and stated that interconnection costs vary on a case-by-case basis depending on factors such as location, proximity of available utility facilities, and future expansion plans. *See*, Exhibit AG-2, Response to AG DR 1-15.

[14] Exhibit AG-5, Response to AG DR 1-22 and Exhibit AG-2, Response to AG DR 1-14.

[15] Exhibit AG-4, Response to AG DR 2-36.

[16] Exhibit AG-8, Response to AG DR 1-24.

A. Yes. I&M intends to simply pool the significant costs of serving these new large loads with other system costs and then allocate them according to existing practices. If new large load customers are costlier to serve than existing customers, then these large load customers may drive up costs for the entire system without fully taking responsibility for the cost increases.

Q. Does the Company acknowledge the risk of cost shifting associated with serving new large load customers?

A. Mr. Loveman states that the Company seeks to balance its obligation to serve new large load customers with risks to other customers and the wider system.[17] However, Mr. Loveman also concedes that the Company "cannot fully insulate itself and its other customers" from risks associated with large load customers.[18]

Q. Is the Company appropriately mitigating the risk of cost shifting from large load customers?

A. No. While the Company suggests that it is seeking to limit the risks of cost shifting, the Company has not even evaluated the potential cost impacts of serving new large load customers, and whether these costs will raise rates on other customers.[19]

Q. Has the Company demonstrated that its proposal will not raise rates for existing customers?

[17] Loveman Direct, p, 5.
[18] *Id*., p. 15.
[19] Exhibit AG-6, Response to AG DR 1-20.

A. No. Although the Company claims that "[a]pproval of the proposed amendments will not increase any existing rates,"[20] it has failed to demonstrate that this would be the case. In response to discovery, the Company indicates only that it "has not proposed any changes to I&M Michigan's existing rates for electric service."[21] This is not the same as demonstrating there will be no cost shifting to other customers.

Q. Is there any evidence to suggest that large load customers could drive rate increases for I&M's other customers?

A. Yes. There is substantial evidence from other jurisdictions that the incremental costs of generation and transmission to serve new large loads can result in rate increases. Further, the limited information that is available suggests that investments to serve new large load customers within I&M's service territory could shift costs onto other customers. I discuss this evidence in the next section of my testimony.

V. <u>There is a Substantial Risk of Cost Shifting Caused by New Large Load Customers that Should be Mitigated</u>

Q. Please describe the evidence that new large load customers in other jurisdictions have driven up generation costs.

A. There is substantial evidence that large load customers are increasing costs on all customers. For example, PJM's Independent Market Monitor has documented that capacity market costs increased 262 percent from 2024 to 2025, driven largely by data center load

[20] I&M's Application, p. 2.
[21] Exhibit AG-7, Response to AG DR 2-34.

additions to the system.[22] For the first time since 2019, capacity costs exceeded transmission costs as a component of wholesale power costs.[23] PJM's most recent capacity auction in December 2025 cleared at a record $333.44 per MW-day price cap, with data centers driving a 5,250 MW increase in the demand forecast for that auction.[24] Without a temporary price cap, the clearing price would have reached approximately $530 per MW-day.[25] To the extent that I&M turns to the wholesale market to meet the increased need for generation capacity resulting from new large loads on its system, the Company could be paying more for this incremental capacity on a per-unit basis than it does to meet its current capacity needs.

Q. Please describe the evidence that new large load customers in other jurisdictions have driven up transmission costs.

A. According to one recent paper, utilities in seven PJM states passed more than $4.3 billion in additional transmission costs to all customers in 2024 alone to connect data centers to the grid.[26] Of 130 transmission connection projects for data centers approved in 2024, utilities assigned costs to all customers for 124 projects—95 percent of the total.[27] Only six projects included customer-specific cost responsibility.[28]

[22] Exhibit AG-10, Monitoring Analytics, LLC. 2025 State of the Market Report for PJM: Volume 2. January 22, 2026, pp. 20-21.
[23] *Id.*, p. 22.
[24] Exhibit AG-11, Utility Dive. "PJM capacity auction clears at record $269.92/MW-day as data centers drive demand." December 18, 2025.
[25] *Id*.
[26] Exhibit AG-12, Union of Concerned Scientists. Data Center Transmission Connection Costs Policy Brief. September 2025, p. 3.
[27] *Id*., p. 5.
[28] *Id*.

Q. What is the risk that new large load customers could increase generation costs for I&M customers?

A. I find this risk to be real and present. While the Company did not conduct any modeling of cost shifting impacts from large load customers, I used the Company's estimate that approximately $200 million would be required to construct a generation unit to serve a hypothetical 50 MW customer to conduct my own assessment of the potential for cost impacts on other customers.[29]

Q. Please describe how you conducted your cost-shifting analysis.

A. First, I adjusted the generation asset cost to account for the projected return that the Company would collect from its customers for this investment over its depreciable life. Assuming a useful life of 30 years for a new thermal asset and a weighted average cost of capital of 6.03 percent, I determine that the total revenue requirement for this unit would be nearly $381 million. Next, I used the currently applicable rates for the Company's Tariff LP to calculate the value of generation revenues from this hypothetical customer that would be collected under the Company's proposed Tariff LP.[30] Since the purpose of this exercise was to evaluate the risk that revenues from the hypothetical 50 MW large load customer would not cover the cost of a new generation asset constructed to serve this customer's load, I focused on the minimum assured revenues that would be received from this

[29] While the Company in its response to AG DR 1-13a-b stated that its estimate of $2000/kW the average for "a diversified set of resource types with different costs, such as nuclear, gas, solar, and wind" (Exhibit AG-2), a recent analysis by Gridlab found that combined cycle gas turbine projects a routinely reporting costs of $2000/kW or more. *See*, Exhibit AG-13, Grid Lab. "The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S." September 2025, p. 4. https://gridlab.org/portfolio-item/gas-tubine-cost-report/ (Last accessed on February 11, 2026).

[30] These rates were provided in an Excel spreadsheet as Response to AG DR 1-1, Attachment 1.

customer if the customer remained for the entire 15-year contract term. I estimated the total revenues that would be generated at 90 percent monthly minimum billing demand and 65 percent monthly minimum energy to be equal to about $265 million total over 15 years. These calculations are documented in Exhibit AG-1.

Q Do your calculations involve any simplifications or caveats?

A. Yes. I have not included revenues that could be received by the Company during any ramp period, nor have I included possible proceeds from the sale of excess capacity to the PJM wholesale market. Both of these potential revenue streams are difficult to quality and uncertain. The customer may not utilize a ramp period, and it is not clear when any generation unit might be constructed relative to the customer ramp period. While the Company could feasibly generate additional revenues through sale of excess capacity to the wholesale market, it is unknown what the scale of excess capacity would be and it is also not clear whether market conditions would permit the sale of capacity excess through the life of this hypothetical new generation asset.

On the incremental cost side, I have not accounted for the cost of environmental compliance, nor have I considered how the PJM reserve margin might meaningfully increase the required size and cost of the hypothetical generation unit. Finally, this exercise does not consider that the customer might be permitted to reduce its contract capacity after the generation unit is constructed, reducing the revenue from this customer.

Q What do you conclude from this analysis of potential generation costs for a new large

load customer?

A. I conclude that there is a meaningful risk that investments in new generation assets to serve large load customers will *not* be covered by revenues from these new customers. This in turn could result in increased costs for all I&M ratepayers.

Q Have you evaluated the risk of cost shifting resulting from transmission and distribution investments to serve new large load customers with I&M's territory?

A. It is difficult to formally evaluate the cost shift risk since I&M provides no specific detail about expected transmission and distribution costs. Of course, this does not mean that the risk is not significant. Further, I am concerned that the Company's facilities allowance policy for commercial and industrial customers, when applied to new large load customers, could result in further cost shifting.

Q Please explain your concern about the Company's facilities allowance policy.

A. The Company's policy for direct connect facilities creates a significant risk of cost-shifting to existing customers. Under the policy, I&M finances interconnection costs when they do not exceed two times the annual capacity power supply and delivery charge revenue anticipated from the customer.[31] Because these large load customers are so *large*, the interconnection costs are likely to be much higher than the Company typically incurs for other commercial and industrial customers. Thus, the Company's policy could result in hundreds of millions of dollars in interconnection costs to be financed by the Company and recovered from all ratepayers. While this policy is not necessarily wrong in concept, it is

[31] Exhibit AG-8, Response to AG DR 1-24.

incoherent when applied to large load customers taking service at transmission voltage – the socialization cost threshold for these customers would largely be driven by expected capacity power supply revenues. Yet the same capacity power supply revenues, when they eventually materialize from the large load customer, would not be used to repay the cost of the interconnection facilities. There is no assurance that the revenues from new large load customers will cover the socialized cost of associated interconnection facilities.

Q Has the Commission addressed facility allowances in any recent cases?

A. Yes. In its final order in the last Consumers Energy rate case, the Commission addressed facilities allowances as a component of that company's economic development rate.[32] While there are distinctions between the Consumers case context and the instant case context, the Commission's concern about the implications of an inflated facilities allowance is relevant here. In the Consumers case, the Commission directed the utility to propose a facilities allowance formulation that would exclude power supply revenues and be based upon limited term; the Commission recognized the concern that a facilities allowance that included power supply revenues could result in cost shifting.[33] The same concern is applicable to I&M.

Q How should the Commission handle direct connect facility costs.

A. The Commission should require that these costs are covered by the individual large load customer, with no socialization of costs through a facilities allowance. The construction of direct facilities is the paradigmatic example of cost causation, and so the costs of the

[32] Case No. U-21585, March 21, 2025, Order, p. 413-425.
[33] Case No. U-21585, March 21, 2025, Order, p. 424-425.

interconnection facility should be borne by the large load customer that is being interconnected. If the Commission is inclined to permit any socialization of direct connect facilities, then it should require that the Company separately track any socialized costs, assign appropriate responsibility for these costs to large load customers at the customer class level, and monitor to ensure that there is no cost shifting resulting from this cost socialization.

Q. Has the Commission previously addressed cost shifting from large load customers?

A. Yes. In the recent Consumers case (Case No. U-21859), the Commission acknowledged significant concerns about cost shifting and cross-subsidization raised by multiple parties. Acknowledging that there was a potential for residential rate increases resulting from new large loads, the Commission stated, "This is unacceptable. A core tenet of ratemaking is that customers are responsible for the costs they impose on the system and the costs required to serve them."[34] The Commission's final order in that proceeding included provisions to prevent cost shifting.

Q. How did the Commission's order in the Consumers case seek to prevent cost shifting caused by large load customers?

A. Noting that there was a lack of information about the cost of serving new large load customers, the Commission ordered Consumers to make a filing with the Commission before each new large load customer commenced taking service from the utility "that clearly demonstrates compliance with the tariff requirements and that costs caused by the

[34] Case No. U-21859, November 6, 2025, Order, p. 116.

interconnecting large load customer to be served under this tariff are not being paid for by other customers."[35] The Commission also ordered that Consumers to file several cost-of-service study (COSS) scenarios in its next rate case.[36]

Q. What were the scenarios that the Commission ordered Consumers to evaluate?

A. The Commission directed Consumers to file six cost allocation and rate design proposals in its next rate case, including: (1) traditional ratemaking with large loads included; (2) same with new large load rate class (100 MW+, 20 MW aggregation threshold); (3) same using 12CP instead of 4CP; (4) traditional ratemaking without large loads; (5) direct assignment of transmission, generation, and distribution costs to new large load rate class; and (6) direct assignment of transmission, generation, and distribution costs to individual large load customers.[37]

Q. How should the Commission proceed in the instant proceeding to mitigate the risk of cost shifting from new large load customers?

A. I recommend that the Commission again find that cost shifting caused by new large load customers is unacceptable, and that it require the Company to undertake modeling to understand the cost implications of serving these new large loads so that any incremental costs can be directly assigned to these new large loads. Specifically, the Commission should order I&M to file the same six cost allocation and rate design scenarios ordered in

[35] *Id*., p. 117.
[36] *Id*., Order, p. 116.
[37] *Id*., Order, p. 116

the Consumers case. Just as in the Consumers case, the current record lacks the information necessary to ensure that large load customers pay the costs they impose on the system.

Q. Do you support creating a separate rate class for large load customers?

A. Yes. It would be best to create a separate rate class for large load customers, for transparency purposes and to facilitate direct assignment of costs. I note that the Commission in Case No. U-21859 found that creation of a separate rate class would be more appropriate within the context of a rate case or other proceeding.[38]

VI. The Commission Should Order Changes to Tariff LP to Reduce Risk and Strengthen Customer Protections

Q. Please describe your concerns with the proposed contract length for new customers.

A. I am concerned that the Company's proposed 15-year contract term is shorter than the useful life of the generating assets that would be built or procured to serve these customers. The Company acknowledges that self-built generation resources typically have depreciation schedules of 30 years or greater, and power purchase agreements generally run 15 to 25 years.[39] A contract term shorter than the asset life creates a risk that Large Load Customers will depart or reduce load after 15 years, leaving existing customers to pay for generation assets that were built exclusively to serve the departed load.

Q. Have other commissions adopted longer contract terms to mitigate this risk?

[38] *Id*., at 105.
[39] Loveman Direct, p. 7.

A. Yes. For example, the Kentucky Public Service Commission approved a 20-year minimum contract term for Kentucky Power's large load tariff, recognizing that longer terms better align with asset life and protect existing customers from stranded cost risk.[40]

The Company's justification for the 15-year term is also internally inconsistent. In I&M's Indiana rate case, the Company's witness requested a 20-year contract term tied to resource useful life.[41] When asked in discovery why I&M proposes only 15 years in Michigan, the Company stated that the additional 5-year ramp period accounts for the difference, but has not explained why useful life considerations would differ between Michigan and Indiana.[42] If the Company's rationale is tied to useful life, then the same 20-year minimum should apply in Michigan.

Q. What is your recommendation for minimum contract length for new large load customers?

A. I recommend a minimum contract term of 20 years to better align with the useful life of generating assets. Self-built generation typically has a 30-year or greater depreciation schedule, and power purchase agreements generally run 15 to 25 years. A 20-year term would reduce the risk of cost-shifting to existing customers while still providing Large Load Customers with a commercially reasonable contract period. I support the Company's proposal for a required sixty months written notice in advance contract termination. I

[40] Order of the Commission. March 18, 2025. Case No. 2024-00305. In the Matter of the Application of Kentucky Power Company d/b/a American Electric Power for Approval of a Large Load Tariff and Associated Service Agreements, p. 3.
[41] Direct Testimony of Andrew Williamson. July 19, 2024. Cause No. 46097. In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to Its Industrial Power Tariff – Tariff I.P, p. 3.
[42] Exhibit AG-9, Response to AG DR 1-9.

further recommend that the Commission adopt an evergreen provision that would automatically extend the contract term in the event that a customer does not provide notice of contract termination within sixty months of the initial contract period, consistent with the Commission's order in the recent Consumers case.[43]

Q. How would the ramp period interact with the minimum contract length?

A. Under the Company's proposal, the Load Ramp Period is separate from and precedes the Initial Contract Term. The Load Ramp Period is the time from when electric service becomes available to the Large Load Customer until the customer's maximum contract capacity is billed, and can be no greater than five years.[44] The Initial Contract Term commences after the Load Ramp Period ends.[45] This means a Large Load Customer could receive up to five years of ramp-up time before the 15-year contract term even begins, extending the total relationship to 20 years but providing contract protections for only 15 of those years. This structure could create additional risk for existing customers if minimum billing demand requirements and exit fees do not apply proportionally during the ramp period.

Q. Please describe how the recommended evergreen provision would function.

A. Under the Company's proposed approach, which I support, a large load customer would be required to provide sixty months' written notice of contract termination. Should this customer not provide the required notice, the evergreen provision would automatically

[43] Case No. U-21859, November 6, 2025, Order, p. 108.
[44] Loveman Direct, p. 13.
[45] *Id*.

extend the contract by an additional five years. This provision would encourage customers to provide sufficient notice of the intent to terminate a contract, and it would help to mitigate against the risk of stranded assets. The evergreen provision would operate independently of any penalty provisions that would apply for providing insufficient notice of termination.

Q. Do you have any concerns regarding the Company's proposal to allow customers to reduce their contract capacity by up to 20 percent?

A. Yes. The Company's proposal to allow Large Load Customers to reduce contract capacity by up to 20 percent is excessive and increases the risk of cost-shifting. It is worth noting that the Commission implicitly recognized a 20 percent reduction allowance to be excessive in the recent Consumers Energy case. In that proceeding, Consumers proposed that it be permitted to authorize a one-time contract capacity reduction at its own discretion, without specifying a percentage limit. The Commission rejected this approach and instead limited contract capacity reductions to no more than 10 percent, finding that this better balanced customer flexibility against the risk of cost-shifting to existing ratepayers.[46]

Q. What is your recommendation for allowed reductions to contract capacity?

A. I recommend limiting contract capacity reductions to no more than 10 percent of the original contracted capacity, consistent with the Commission's decision in the Consumers Energy case, to reduce the risk of stranded assets and cost shifting.[47] Further, I recommend

[46] Case No. U-21859, November 6, 2025, Order.
[47] *Id*, p. 111.

that any reduction in contract capacity be evaluated within a contested case proceeding and be subject to Commission approval

For any capacity reductions beyond 10 percent, the Company should be required to either: (1) collect a pro-rated exit fee based on the amount of the reduction, or (2) seek Commission review and approval through a contested case proceeding if the Company asserts the exit fee is unnecessary.

It is important to recognize that reductions in contract capacity directly affect the exit fee calculation, as the exit fee is based on the customer's remaining contract obligations. If the Company seeks to mitigate or waive the exit fee for capacity reductions—for example, through reassignment of contract rights to a new customer—such mitigation must be subject to Commission oversight and approval as part of a contested proceeding to ensure that existing customers are not harmed by stranded costs.

Q. Please discuss your concerns about misaligned incentives under the Company's proposal.

A. It is in the interest of the Company and its customers to ensure that large load customers provide sufficient notice before exiting the system. However, it is not clear how the Company would ensure that notice is provided, since the Company has not proposed any penalty provision that would apply to customers who fail to provide sufficient notice.

Q. How do you recommend that the Company address these incentive issues?

A. To ensure that customers do not depart without providing sufficient notice, the Company should specify a penalty that would apply in such cases, which could be effectuated as an adder to the exit fee.

Q. What modifications do you propose to the exit fee?

A. I recommend several modifications to ensure the exit fee prevents cost-shifting and protects existing customers. First, the exit fee should be applicable from the point the Company executes an Electric Service Agreement with a Large Load Customer, and should apply during the ramp-up period. By default the exit fee applicable during the ramp-up period would be calculated using the customers' contract capacity, with the understanding that the customer or the Company might request mitigation (subject to review in a contested case proceeding) based on the use of capacity planning milestones during the ramp-up. For example, if a customer and the company are able to structure build-out of the customer's capacity such that they could plan to reach partial capacity of 250 MW in year three of a ramp-up schedule without investments for capacity beyond that milestone, they might request (subject to review) that an exit fee assessed for exit during the build-out period to reach that milestone should be calculated based on 90 percent of that 250 MW milestone capacity for the remainder of the contract term. This ensures that customers cannot exit during ramp-up without consequence when the Company may have already made substantial investments, while also incentivizing a planned build-out of incremental investments to potentially reduce stranded asset risk.

Second, the exit fee should be due and payable to the Company upon the effective date of contract termination, upon notice of election to take service from an alternative electric supplier, or upon the effective date of a capacity reduction.

Third, any waiver or reduction of the exit fee should be subject to Commission review and approval as part of a contested case proceeding to ensure that such modifications do not harm other customers or create stranded assets.

Fourth, the exit fee should be calculated including any contract extension due to the evergreen provision.

Q. What is your recommendation for collateral?

A. I recommend that the customer be required to post collateral equal to the applicable exit fee, which is the total Minimum Charge multiplied by the number of months remaining on the full term of the contract, to be recalculated annually. This approach would provide greater than would the Company's approach, and it is consistent with the decision of the Commission in the Consumers Energy data center case.[48]

The two-year collateral requirement proposed by the Company is insufficient to protect existing customers from the risk of stranded costs. In the Consumers case, the Attorney General demonstrated that two years of non-fuel revenues would barely cover estimated interconnection costs alone, without accounting for the substantial generation and transmission investments required to serve large loads.[49]

[48] *Id*., pp. 112-114.
[49] Attorney General's Initial Brief, Case No. U-21859, pp. 29-30.

The collateral requirement should be recalculated annually as the contract term progresses and the exit fee decreases, reflecting the declining risk as the Company recovers its investments.[50] Acceptable forms of collateral should include a standby irrevocable letter of credit or cash that earns interest.

Q. How should the costs of environmental compliance be recovered?

A. Large load customers should be required to cover their added cost of compliance for meeting the resource portfolio standards of PA 235. Specifically, new large load customers should be required to enter into contracts with the Company for procurement of at least 60 percent of their incremental energy requirements to be supplied by renewable resources. This ensures that large load customers bear responsibility for the incremental renewable energy procurement costs they cause, rather than socializing these costs to existing customers.

Additionally, if large load customers seek to be eligible as an enterprise data center under MCL 205.54ee and 205.94cc—which provide certain tax exemptions—they should be required to meet the 90 percent clean energy procurement standard established under that statute. This requirement ensures consistency between the benefits these customers receive through tax exemptions and their obligations to procure clean energy.

Q. Do you have any comments on the assignment of rights?

A. Consistent with the Commission's decision in Consumers Energy's case U-21859, Large Load Customers should be prohibited from reassigning contract capacity to other

[50] Case No. U-21859, November 6, 2025, Order, pp. 112-114.

customers on their own. Any assignment of contract rights must be subject to Commission review and approval in a contested case proceeding.[51]

Q. Does that complete your testimony?

A. Yes.

[51] *Id*., pp. 110-111.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate,* April 2024 – Present; *Senior Associate,* June 2021 – April 2024; *Associate,* July 2018 – June 2021.

- Provides research, analysis, and consulting services, frequently in the context of regulated proceedings, with expertise in the following topic areas:
    - Rate design and performance-based regulation: Evaluates utility proposals and formulates new recommendations based on best practices and informed by innovative emerging models. Evaluates rate designs for consistency with policy goals using quantitative modeling and jurisdictional data. Provides expert testimony and other formal input in the context of regulated proceedings.
    - Benefit-cost analysis: Evaluates utility BCAs with reference to best practices, including emerging standards for grid modernization and distributed energy resources. Engaged in the development of new BCA practices in the arenas of grid modernization and resilience.
    - Macroeconomic analysis: Uses the IMPLAN model in conjunction with primary research and analysis and core economic principles to evaluate the GDP, job, and income implications of major grid changes.
- Contributing author to reports covering a range of topics including plant decommissioning, transportation electrification, and distributed energy resources (DER) growth.

University of Massachusetts Boston, MA. *Graduate Teaching and Research Assistant,* 2017 – 2018

- Led ecosystem-valuation workshops for EPA-funded initiative to shape resilience policymaking in the Great Bay region of New Hampshire.
- Served as a teaching assistant in graduate econometrics course and undergraduate macroeconomics and urban economics courses.

Notre Dame Education Center and Jewish Vocational Service Boston, MA. *Math Instructor*, 2012 – 2017

- Taught foundational math to adult learners and standard high school math curriculum to students in non-traditional school program.

The City of New York New York, NY. *Senior Investigator*, 2007 – 2010

- Investigated complaints against officers of the New York City Police Department and issued disciplinary recommendations in formal reports to the agency board.

EDUCATION

University of Massachusetts, **Boston,** Boston, MA
Master of Arts in Applied Economics, 2018
Recipient of the Arthur MacEwan Award for Excellence in Political Economy

McGill University, Montreal, Quebec
Bachelor of Arts in History, 2007

PUBLICATIONS

Goldenberg, C., B. Havumaki, C. Lane, M. Whited, G. Wilson. *Fixing Multiyear Rate Plans: Building a firm foundation for cost control.* 2025. Rocky Mountain Institute and Synapse Energy Economics.

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Pennsylvania Public Utility Commission (Docket No. R-2025-3057164): Direct and Surrebuttal Testimony of Ben Havumaki on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania. December 22, 2025, and February 9, 2025.

Nova Scotia Energy and Review Board (NSEB M12179): Expert Evidence of Ben Havumaki on behalf of Counsel to Nova Scotia Energy Board. May 29, 2025.

Public Utilities Commission of New Hampshire (Docket No. DE 24-070): Direct Testimony of Ben Havumaki. On behalf of the Office of the Consumer Advocate. January 23, 2025.

New York Public Service Commission (Cases 24-E-0322 and 24-G-0323): Direct Testimony of UIU Rate Panel. September 26, 2024.

Pennsylvania Public Utility Commission (Docket No. R-2023-3037933): Direct Testimony of Ben Havumaki on behalf of Power Interfaith. May 31, 2023.

Nova Scotia Utility and Review Board (NSEB M11199): Expert Evidence of Ben Havumaki on behalf of Counsel to Nova Scotia Energy Board. August 28, 2023.

New Brunswick Energy and Utilities Board (Matter 529): Expert Evidence of Synapse Energy Economics, Inc. On behalf of the New Brunswick Energy and Utilities Board. April 25, 2023.

Minnesota Public Utilities Commission (Docket No. E-002/GR-21-630): Direct and Surrebuttal Testimony of Ben Havumaki regarding Xcel Energy's application to increase rates. On behalf of the Division of Energy Resources of the Minnesota Department of Commerce. December 6, 2022, and October 3, 2022.

Public Utilities Commission of New Hampshire (Docket No. DE 20-161): Direct Testimony of Tim Woolf and Ben Havumaki regarding Eversource's 2020 least-cost integrated resource plan. On behalf of the Office of the Consumer Advocate. August 19, 2022.

Public Service Commission of West Virginia (Case No. 21-0857-E-CN): Direct Testimony of Ben Havumaki regarding the petition of Monongahela Power Company and the Potomac Edison Company for the issuance of a certificate of public convenience and necessity for environmental compliance and modernization, upgrade, and improvement program and related surcharge for coal-fired boilers at electric power plants. On behalf of Appalachian Mountain Associates. July 20, 2022.

Illinois Commerce Commission (Docket No. 22-0067): Direct and Rebuttal Testimony of Melissa Whited and Ben Havumaki regarding the performance incentive mechanisms and tracking metrics proposed by Commonwealth Edison Company and Ameren Illinois Company. On behalf of the State of Illinois. April 6, 2022.

Public Utilities Commission of New Hampshire (Docket DG 21-104): Direct Testimony of Ben Havumaki and Courtney Lane Regarding Northern Utilities' Proposed Rate Increase for the Residential Class and Multi-Year Rate Plan. On behalf of New Hampshire Office of the Consumer Advocate. April 1, 2022.

Illinois Commerce Commission (Docket No. 22-0063): Direct Testimony of Melissa Whited and Ben Havumaki regarding performance incentive mechanisms and tracking metrics proposed by Ameren Illinois Company. On behalf of the State of Illinois. March 30, 2022 and May 25, 2022.

Public Utilities Commission of New Hampshire (Docket DG 21-104): Direct Testimony of Courtney Lane and Ben Havumaki regarding Northern Utilities Inc.'s proposed multi-year rate plan, which includes a proposed residential customer charge, the company's reliance on the minimum-system method for classifying distribution mains costs and its implication for rate design and class cost allocation. On behalf of the Office of the Consumer Advocate. April 1, 2022.

Public Utilities Commission of New Hampshire (Docket No. DE 21-030): Direct testimony of Melissa Whited and Ben Havumaki regarding Until Energy Systems' multi-year rate plan, grid modernization proposal, overall rate increases for the residential class, allocation of costs among rate classes, increase to the residential customer charge, and revenue decoupling mechanism. November 23, 2021.

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Hawaii Public Utilities Commission (Docket No. 2018-0088): Panel testimony by Ben Havumaki regarding performance incentive mechanisms. On behalf of the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs. September 21, 2020.

Georgia Public Service Commission (Docket No. 42516): Direct Testimony of Melissa Whited and Ben Havumaki. On behalf of Sierra Club. October 17, 2019.

PRESENTATIONS

Woolf, T. B Havumaki. 2022. “Economic Assessment of Grid Modernization Plans.” Presentation at the NASUCA 2022 Mid-Year Meeting.

generation cost

		Source
Customer size (MW)	50	*Loveman Direct, p. 7*
Average resource cost ($/kW)	2000	*Loveman Direct, p. 7*
Accredited capacity value	0.5	*Loveman Direct, p. 7*
Total capital cost of resource	$200,000,000	*Loveman Direct, p. 7*
WACC	0.0603	*PSC Order in Case No. U-21461*
Useful life (years)	30	*Conservative assumption based upon typical useful life for thermal generation units*
Year 1 return on resource	$12,060,000	
Year 30 return on resource	$0	
Total return on resource	$180,900,000	
Total resource cost inclusive of return	$380,900,000	

LP Tran Bill

AG DR 1-1 Attachment 1: Adaptation to Calculate Generation Revenues for Hypothetical 50 MW Large Load Customer

Indiana Michigan Power Company - Michigan
Large Power - Transmission
Tariff Code: 310
Base Rates, Rider Rates in Effect as of 9/1/2025

Billing Parameters		Standard	Proposed Minimum (no load)	Current Minimum (no load)
Demand (kW):		50,000.0	45,000	27,000
On-Peak kWh Usage:		276,743,000	0	0
Off-Peak kWh Usage:		343,757,000	0	0
Total kWh Usage:		620,500,000	0	0
Total Energy for Minimum Charge Calculation:			23,725,000	0
45%	Assumed on-peak			
55%	Assumed off-peak			
1700%	Assumed Load Factor			

42500000000

Standard Tariff Billing

Bill Calculation	Units	Rates: Power Supply	Rates: Delivery	Rates: Total		Billing: Power Supply	Billing: Delivery	Billing: Total
Customer Charge			$ 880.00	$ 880.00			$ 880.00	$ 880.00
On-Peak Energy Charge (1st 210 kWh * on peak demand (kW)	10,500,000 kWh	$ 0.04753		$ 0.04753	/kWh	$ 499,065.00		$ 499,065.00
On-Peak Energy Charge (remaining on-peak kWh)	266,243,000 kWh	$ 0.03002		$ 0.03002	/kWh	$ 7,992,614.86		$ 7,992,614.86
Off-Peak Energy Charge	343,757,000 kWh	$ 0.03002		$ 0.03002	/kWh	$ 10,319,585.14		$ 10,319,585.14
Demand Charge	1,000,000.0 kW	$ 23.19	$ 0.40	$ 23.59	/kW	$ 23,190,000.00	$ 400,000.00	$ 23,590,000.00
Reactive Demand Charge	0.0 kVAR		$ 1.50	$ -	/kVAR			$ -
Base Charges						**$ 42,001,265.00**	**$ 400,880.00**	**$ 42,402,145.00**
Riders								
Power Supply Cost Recovery Factor	620,500,000 kWh	$ 0.00358		$ 0.00358	/kWh	$ 2,221,390.00		$ 2,221,390.00
Rate Realignment Surcharge	620,500,000 kWh	$ 0.000370		$ 0.000370	/kWh	$ 229,585.00		$ 229,585.00
Energy Waste Reduction Surcharge	1 Bill		$ 1,660.77	$ 1,660.77			$ 1,660.77	$ 1,660.77
Nuclear Decommissioning Surcharge	620,500,000 kWh		$ -	$ -	/kWh		$ -	$ -
Renewable Energy Surcharge	1 Bill	$ -		$ -		$ -		$ -
Net Lost Revenue Tracker Surcharge	1 Bill	$ -	$ -	$ -		$ -	$ -	$ -
Low-Income Energy Assistance Fund Surcharge	1 Bill		$ 1.25	$ 1.25			$ 1.25	$ 1.25
Phase-In Rate Adjustment Rider	620,500,000 kWh	$ -	$ -	$ -	/kWh	$ -	$ -	$ -
Tax Reform Credit B Rider	1 Bill	$ -	$ -	$ -		$ -	$ -	$ -
Tax Reform Credit C Rider (kWh)	620,500,000 kWh	$ -	$ -	$ -	/kWh	$ -	$ -	$ -
Tax Reform Credit C Rider (kW)	1,000,000.0 kW	$ -	$ -	$ -	/kWh	$ -	$ -	$ -
Riders Total						**$ 2,450,975.00**	**$ 1,662.02**	**$ 2,452,637.02**
Total Billing						**$ 44,452,240.00**	**$ 402,542.02**	**$ 44,854,782.02**
Yearly Billing:						**$ 533,426,880**	**$ 4,830,504**	**$ 538,257,384**

Minium Billing at 60% Demand

Units	Billing: Power Supply	Billing: Delivery	Billing: Total
1	$ -	$ 880.00	$ 880.00
	$ -	$ -	$ -
	$ -	$ -	$ -
	$ -	$ -	$ -
27,000	$ 626,130.00	$ 10,800.00	$ 636,930.00
	$ -	$ -	$ -
	$ 626,130.00	**$ 11,680.00**	**$ 637,810.00**
	$ -	$ -	$ -
	$ -	$ -	$ -
1	$ -	$ 1,660.77	$ 1,660.77
	$ -	$ -	$ -
1	$ -	$ -	$ -
1	$ -	$ -	$ -
1	$ -	$ 1.25	$ 1.25
	$ -	$ -	$ -
1	$ -	$ -	$ -
	$ -	$ -	$ -
27,000	$ -	$ -	$ -
	$ -	**$ 1,662.02**	**$ 1,662.02**
	$ 626,130.00	**$ 13,342.02**	**$ 639,472.02**
	$ 7,513,560	**$ 160,104**	**$ 7,673,664**

Minimum Billing at 90% Demand & 65% Minimum Energy (Minimum Charge)

Bill Calculation	Units	Rates: Power Supply (Generation)	Rates: Delivery	Rates: Total	Billing: Power Supply	Billing: Delivery	Billing: Total
Customer Charge			$ 880.00	$ 880.00		$ 880.00	$ 880.00
On-Peak Energy Charge (1st 210 kWh * on peak demand (kW)	0 kWh	$ 0.04385		$ 0.04385	$ -	$ -	$ -
On-Peak Energy Charge (remaining on-peak kWh)	0 kWh	$ 0.02610		$ 0.02610	$ -	$ -	$ -
Off-Peak Energy Charge	23,725,000 kWh	$ 0.02610		$ 0.02610	$ 619,308.37	$ -	$ 619,308.37
Demand Charge	45,000.0 kW	$ 18.92	$ 0.40	$ 19.32	$ 851,592.34	$ 18,000.00	$ 869,592.34
Reactive Demand Charge	0.0 kVAR		$ 1.50	$ -	$ -	$ -	$ -
Base Charges					**$ 1,470,900.71**	**$ 18,880.00**	**$ 1,489,780.71**
Riders							
Power Supply Cost Recovery Factor	23,725,000 kWh	$ 0.00358		$ 0.00358	$ 84,935.50	$ -	$ 84,935.50
Rate Realignment Surcharge	23,725,000 kWh	$ 0.000370		$ 0.000370	$ 8,778.25	$ -	$ 8,778.25
Energy Waste Reduction Surcharge	1 Bill		$ 1,660.77	$ 1,660.77	$ -	$ 1,660.77	$ 1,660.77
Nuclear Decommissioning Surcharge	23,725,000 kWh		$ -	$ -	$ -	$ -	$ -
Renewable Energy Surcharge	1 Bill	$ -		$ -	$ -	$ -	$ -
Net Lost Revenue Tracker Surcharge	1 Bill	$ -	$ -	$ -	$ -	$ -	$ -
Low-Income Energy Assistance Fund Surcharge	1 Bill		$ 1.25	$ 1.25	$ -	$ 1.25	$ 1.25
Phase-In Rate Adjustment Rider	23,725,000 kWh	$ -	$ -	$ -	$ -	$ -	$ -
Tax Reform Credit B Rider	1 Bill	$ -	$ -	$ -	$ -	$ -	$ -
Tax Reform Credit C Rider (kWh)	23,725,000 kWh	$ -	$ -	$ -	$ -	$ -	$ -
Tax Reform Credit C Rider (kW)	45,000.0 kW	$ -	$ -	$ -	$ -	$ -	$ -
Riders Total					**$ 93,713.75**	**$ 1,662.02**	**$ 95,375.77**
Total Billing					**$ 1,564,614.46**	**$ 20,542.02**	**$ 1,585,156.48**
Yearly Billing:					**$ 18,775,373**	**$ 246,504**	**$ 19,021,878**

Total Power Supply Generation Revenues $ 264,762,127.49

LP Tran Rate Summary

Case No. U-21986
AG DR 4-62
Attachment 1

	Large Power - Tran Rates*	Power Supply		Delivery	Total	% Transmission-Related	Power Supply Non-Capacity Estimated Transmission Rates	Power Supply Non-Capacity Estimated Generation Rates
		Capacity	Non-Capacity					
Base Rates	Service Charge			$ 880.00	$ 880.00			
	Demand Charge ($ per kW)	$ 6.06	$ 17.48	$ 0.57	$ 24.11	26%	$ 4.62	$ 18.92
	Energy Charge (cents per kWh)							
	First 210 on-peak kWh per kW	1.775	3.043		4.818	14%	0.4326	0.0439
	For all over 210 on-peak kWh per kw		3.043		3.043	14%	0.4326	0.0261
	For all off-peak kWh		3.043		3.043	14%	0.4326	0.0261
Surcharge	Power Supply Cost Recovery (PSCR) Factor		1.93		1.93	63%	1.2100	0.7200

*Other non-Transmission related surcharge rates not shown $ 19.49

	Total LP Class	Source:
PS_TRAN Cost Allocation Before Net Cone Capacity Reallocation - Revenue Target for Rate Design	$ 8,633,588	Exhibit A-16,Schedule F-1.1 Projected CCOSS_Final Combined_Staff Version_Corrected, tab A-16,F1.1 (Class Study) p.1-7, row: 2581
PS_TRAN Cost Allocation After Net Cone Capacity Reallocation - Revenue Target for Rate Design	$ 21,252,830	Exhibit A-16,Schedule F-1.1 Projected CCOSS_Final Combined_Staff Version_Corrected, tab A-16,F1.1 (Class Study) p.1-7, row: 2649
% Actual PS_TRAN Cost before Reallocation	40.62%	
Adjustments to Staff-Provided Revenue Targets**	$ 21,252,698	EMB 21461 Rate Design for ERATTA2 MS cust charge, tab "CCOS Data" cells D56, D34
Amount PS_TRAN Cost	$ 8,633,534	EMB 21461 Rate Design for ERATTA2 MS cust charge, tab "CCOS Data" cells D56, D34
Power Suply Demand Non-Capacity Total Revenue Target	$ 21,252,698	
Less: EDR and Green Power Revenue	($1,556,469)	EMB 21461 Rate Design for ERATTA2 MS cust charge, tab "LP"
Total Power Supply Demand Non-Capacity revenue Target for Rate Design	$ 22,809,167	
65% Collection of Demand Cost through Demand Charge	$ 14,826,323	EMB 21461 Rate Design for ERATTA2 MS cust charge, tab "LP" cell I171
Amount Power Supply Non Capacity Demand Cost Recovered through Demand Charge	65%	
Amount Power Supply Non Capacity Demand Cost Recovered through Energy Charge	35%	
PS-TRAN Cost Percentage in PS NC Demand Rate	26.4%	
PS-TRAN Cost Percentage in PS NC Energy Rate	14.2%	
	40.6%	
	0.00 check	

**Minor differences to Staff-provided rate design

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-13

Request

Referring to the Application Testimony of Caleb Loveman at 7:13 – 20:

a) Explain whether the described "$200 million to serve a 50 MW load" scale upward such that a 150MW customer would entail $600 million in incremental generation investment under this framework and/or such that a 1GW customer would entail $4 billion in incremental generation investment under this framework.

b) Identify whether the described "$200 million to serve a 50 MW load" includes a cost of capital amount. If so, please identify any cost of capital component within that description and produce all analysis, calculations, and assumptions used to arrive at that cost of capital amount.

c) Confirm whether witness Loveman's reference to "Michigan's energy policies" at 7:20 is intended to include the cost of complying with PA 235 to accommodate the added retail demand from Large Load Customers.

d) Please identify any estimated PA 235 compliance costs coinciding with an incremental 50MW load as the Company uses in its description of "$200 million to serve a 50 MW load."

e) Provide all analyses and calculations used in arriving at your responses to Sub - Questions 13.a -d above, along with all inputs and assumptions. To the extent not produced in response to a prior question or sub-question, please further produce such supporting analyses, calculations, inputs, and assumptions as to witness Loveman's description of $200 million in generation investment to serve a 50 MW load.

Response

I&M objects to the request on the grounds and to the extent the request seeks a compilation, analysis, study, or calculation the Company has not performed and objects to performing. I&M further objects to the request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent the request seeks "all" "analysis and calculations…". Subject to and without waiver of the foregoing objection, I&M provides the following response.

a.-b. This hypothetical represents what an average resource cost could be for a diversified set of resource types with different costs, such as nuclear, gas, solar, and wind. The point of this example was not to predict or precisely represent what the average resource cost would be, nor was it intended to be scalable as the question

suggests. Rather the purpose was to consider reasonable assumptions based on I&M's experience that are within a range of values associated with different types of resources that would reasonably illustrate the significance of the financial commitments I&M will need to make to provide generation service as I&M's system load grows due to new Large Load customers.

c. Confirmed.

d. The Company has not identified any estimated compliance costs with PA 235 with regard to any hypothetical future loads.

e. See objection.

Preparer:

Caleb R. Loveman

As to Objections:

Counsel

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-14

Request

Referring to the Application Testimony of Caleb Loveman at 7:13 – 17, please identify any estimated "transmission investments" associated with generation build -out required to serve any incremental Large Load Customer load, such as a 50MW or other -sized incremental load as discussed in Sub -Question No.13.a above, or any aggregate incremental load such as discussed in Question No. 11 above. Please further produce any analysis and calculations supporting such estimates, along with all inputs and assumptions.

Response

Any future load growth will be served by I&M's system of generation resources available to serve its Michigan retail customers, not specific "generation build-out to serve any incremental Large Load Customer" resources as alluded to in the question. Transmission investments associated with any generation build will vary on a case-by-case basis and I&M does not know at this time what transmission investments will be needed.

Preparer:

Caleb R. Loveman
Jomar Perez-Ramos

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-15

Request

Please produce estimates for all facility -interconnection costs (or range of such costs) the Company expects to incur to serve a Large Load Customer of the 50MW size referenced in the Application Testimony of Caleb Loveman at 7:13 – 17, including:

a) All distribution interconnection costs, such as the costs of additional transformer substations to serve the customer;

b) The cost of transmission investments necessary to interconnect such a customer; and

c) Any other categories of costs not captured within Sub -Questions No. 15.a-b above.

Response

I&M objects to the request on the grounds and to the extent the request seeks a compilation, analysis, study, or calculation the Company has not performed and objects to performing. Subject to and without waiving that objection, I&M provides the following response.

a.-c. Interconnection costs vary on a case-by-case basis and various factors need to be considered such as location, proximity of available utility facilities, future expansion plans, etc. The Company has not identified Large Load Customers and its proposal is in anticipation of a Large Load Customer seeking service at some point in the future.

Preparer:

Caleb R. Loveman
Jomar Perez-Ramos

As to Objections:

Counsel

INDIANA MICHIGAN POWER COMPANY

MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 2
CASE NO. U-21986

DATA REQUEST NO. AG DR 2-40

Request

Refer to CRL-1. At what voltage does the Company anticipate that large load customers will take service?

Response

I&M has not entered into any agreements with Large Load Customers in its Michigan service territory and cannot speculate what specific voltage future Customers will need.

Preparer:

Caleb R. Loveman

INDIANA MICHIGAN POWER COMPANY

MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 2
CASE NO. U-21986

DATA REQUEST NO. AG DR 2-36

Request

Refer to Loveman Direct Testimony p.6 and 9 regarding the long-term investments and other financial commitments I&M will be required to make in transmission assets to serve Large Load Customers in its Michigan service territory:

a) Describe the types of transmission investments that I&M anticipates needing to make. For each type of potential transmission investment required, identify what customer or groups of customers would pay for those costs, and how the costs would be allocated.
b) Has the Company conducted any studies of the transmission system upgrades required to serve prospective new Large Load Customers in the "preliminary interest stage" described on p.4 of Loveman's Direct Testimony? If yes, provide such studies. If no, explain why not.
c) Has the Company more generally estimated any hypothetical costs of the potential transmission investments required to serve Large Load Customers in its Michigan service territory? If yes, provide such estimations as well as the underlying analyses and calculations for such estimations along with all inputs and assumptions. If no, explain why not.

Response

a. To connect new load to the grid, three types of enhancements may be required. First, direct connect facilities are needed in almost all instances to physically connect customer facilities to the grid. Second, local upgrades are transmission infrastructure enhancements made to the existing grid in the form of new or rebuilt assets to improve transmission infrastructure in the local vicinity of the customer's location so power can be reliably delivered to the customer facility. Third, regional upgrades are enhancements to the regional transmission network that is responsible for bringing power to the local network from the broader regional grid. These enhancements will vary on a case by case basis.

CIAC would be charged to Large Load Customers for direct connect facilities in a manner similar to how it is charged and applied to all other Commercial and Industrial customers. As stated in the current tariff and terms and conditions of service on sheet C-12.00, Section B, Paragraph (i), I&M "will finance the construction cost necessary to extend its facilities to serve commercial or industrial customers when such investment does not exceed two times the annual capacity power supply and delivery charge revenue

anticipated to be collected from customers initially served by the extension." One hundred percent (100%) of the costs associated with temporary infrastructure and premium infrastructure service connections will be charged to the customer. The allocation of other transmission related costs whether specific for Large Load Customers, is governed.by the PJM Interconnection, LLC (PJM) Tariff as approved by the Federal Energy Regulatory Commission (FERC).

b. Yes, since 2025 the Company has conducted eight studies for Large Load Customer requests in MI. The preliminary interest stage study consists of a high level screening to determine the system's ability to support the requested load amount. This consists of steady state N-1 thermal and voltage analysis. Should the customer be interested in moving forward, the Company would then conduct a more detailed N-1-1 thermal and voltage analysis to determine any necessary upgrades on the Transmission system to be able to support the load addition. These studies include Critical Energy Infrastructure Information. Because the disclosure of CEII could endanger the public welfare and security such information is not being produced in discovery.

c. No. The Company only produces cost estimates for specific potential customers. These cost estimates are specific to each prospective customer and produced on a case by case basis. The cost estimates follow I&M's normal estimating process and have typical cost breakdowns that include Construction Labor, Engineering, Material etc.

Preparer:

Caleb R. Loveman

Jomar Perez-Ramos

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-22

Request

Referring to I&M's MPSC Case No. U -21461, Application Testimony of Company witness Hornyak at 11:7 – 19:

a) Confirm whether the Company still uses a 4CP electric plant in service production cost allocation methodology with 75% demand allocation and 25% energy allocation.

b) If not confirming in response to Question No. 22.a. above, please explain the Company's electric plant in service production cost allocation methodology and identify the testimony and exhibits addressing that cost allocation methodology in prior or ongoing MPSC cases.

Response

a. I&M confirms this was the methodology used in I&M's most recent Michigan base rate case, Case No. U-21461.

b. Not applicable.

Preparer:

Jenifer L. Fischer

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-20

Request

Please provide all analyses conducted by or at the direction of I&M to analyze the potential impact of Large Load Customers on:

a) I&M's net income or profit;

b) I&M's cost of service study results, including cost allocation to customer classes;

c) Cost-shifting or cross -subsidization among customer classes; and

d) Residential rate or bill impacts.

Please provide the requested documents in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Response

a-d. I&M has not conducted any such analyses.

INDIANA MICHIGAN POWER COMPANY

MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 2
CASE NO. U-21986

DATA REQUEST NO. AG DR 2-34

Request

Refer to the Company's Application p.3 stating "Approval of the proposed amendments will not increase any existing rates:"

a) Explain how the Company determined that the proposed Tariff LP amendments will not increase existing rates.
b) In live, unlocked Excel file format with all links and formulas intact, provide the analysis the Company has conducted that substantiates the statement that the proposed amendments will not increase existing rates. Explain how the analysis demonstrates the statement. Describe all assumptions that the Company made in order to develop this analysis.

Response

a. As explained in I&M's case-in-chief, I&M's proposal is to establish a clear set of Terms and Conditions applicable to Large Load Customers. I&M has not proposed any changes to I&M Michigan's existing rates for electric service and therefore there is no increase to existing rates.

b. I&M does not have any such analysis.

Preparer:

Caleb R. Loveman

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-24

Request

Referring to the Company's Application Exhibit IM1 -1 (CRL -1) at 7:

a) Explain what portion of costs for upgrades to transmission, distribution, and/or generation resources to serve Large Load Customers the Company envisions will be covered through a Contribution in Aid of Construction (CIAC) payment.

b) To the extent the Company envisions that some portion of costs for upgrades to transmission, distribution, and/or generation resources to serve Large Load Customers will not be covered through CIAC payments, explain whether the Company considered tariff or contract provisions, or other mechanisms, by which CIAC payments would cover some further portion of such costs. If so, please explain the basis for not addressing such issues in the proposed tariff revisions and application. If not, please explain why not.

Response

a) CIAC would be charged to Large Load Customers in a manner similar to how it is charged and applied to all other Commercial and Industrial customers. As stated in the current tariff and terms and conditions of service on sheet C-12.00, Section B, Paragraph (i), I&M "will finance the construction cost necessary to extend its facilities to serve commercial or industrial customers when such investment does not exceed two times the annual capacity power supply and delivery charge revenue anticipated to be collected from customers initially served by the extension." One hundred percent (100%) of the costs associated with temporary infrastructure and premium infrastructure service connections will be charged to the customer.

b) Please see p. 16 of Mr. Loveman's direct testimony and I&M's proposed Temporary Service provision for proposed tariff provisions requiring Large Load Customers to pay all costs for requested temporary service.

Preparer:

Ashley Savieo
Caleb R. Loveman

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 1
CASE NO. U-21986

DATA REQUEST NO. AG DR 1-9

Request

Referring to the Direct Testimony of Company witness Andrew Williamson in its Cause No. 46097 before the Indiana Utility Regulatory Commission, specifically at 3:13 – 15 in witness Williamson's testimony, explain why the Company is here requesting a 15 -year minimum "Initial Contract Term" as opposed to a 20 -year minimum term as it requested in its Indiana case.

Response

In Indiana Cause No. 46097, I&M's original requested contract term of 20 years did not include a specified load ramp period that would be in addition to the 20-year contract term. In the current case before the Michigan Public Service Commission, the proposed Contract Term reflects a period of up to 20 years which includes a 15-year Initial Contract Term and, if designated by a Large Load Customer, a Load Ramp Period of no greater than 5 years. Please also see I&M's response to AG DR 1-5 subparts a. and b.

Preparer:

Caleb R. Loveman

Market Monitor Report

MC

January 22, 2026

IMM

Monitoring Analytics

CURRENT ISSUES

CAPACITY MARKET

IMM 2027/2028 BRA Report Part A

- **Analysis of the 2027/2028 RPM Base Residual Auction Part A. January 5, 2026.**
- **Focus on:**
  - **Impact of Agreement re maximum price**
  - **Impact of data center load**

Increase in capacity market revenues due to the inclusion of the data center load in the peak load forecast by Delivery Year

	Above Embedded	All Data Center Load
2025/2026 Delivery Year	$7,742,960,157	$9,332,103,858
2026/2027 Delivery Year	$7,271,197,971	$7,271,197,971
2027/2028 Delivery Year	$6,244,523,827	$6,497,653,512
Total	$21,258,681,955	$23,100,955,341

Reserve margin calculation: 2026/2027 RPM BRA and 2027/2028 RPM BRA

	Reserve Margin Calculation		
	2026/2027 RPM BRA	2027/2028 RPM BRA	Formula
Forecast peak load ICAP (MW)	159,329.1	164,579.0	A
FRR peak load ICAP (MW)	12,633.9	12,201.9	B
PRD ICAP (MW)	115.0	115.0	C
Installed reserve margin (IRM)	19.1%	20.0%	D
Pool-Wide Accredited UCAP Factor	76.99%	77.17%	E
Forecast pool requirement (FPR)	0.9170	0.9260	F=(1+D)*E
Cleared UCAP (generation and DR)	134,205.3	134,478.1	G
Cleared ICAP (generation and DR)	174,315.2	174,262.1	H=G/E
RPM peak load ICAP (MW)	146,580.2	152,262.1	J=A-B-C
Reserve margin ICAP (MW)	27,735.0	22,000.0	K=H-J
Reserve margin (%)	18.9%	14.4%	L=K/J
Reserve cleared in excess of IRM ICAP (MW)	(261.8)	(8,452.4)	M=K-D*J
Reserve cleared in excess of IRM (%)	(0.2%)	(5.6%)	N=M/J
RPM peak load UCAP (MW)	112,852.1	117,500.7	P=J*E
RPM reliability requirement UCAP (MW)	134,414.0	140,994.7	Q=J*F
Reserve margin UCAP (MW)	21,353.2	16,977.4	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	(208.7)	(6,516.6)	S=G-Q

PJM Peak Load between 2009 and 2025

	Date	Hour Ending (EPT)	PJM Load (MWh)
2009	Mon, August 10	17	123,900
2010	Tue, July 06	17	133,297
2011	Thu, July 21	17	154,095
2012	Tue, July 17	17	150,879
2013	Thu, July 18	17	153,790
2014	Tue, June 17	18	138,448
2015	Tue, July 28	17	140,266
2016	Thu, August 11	16	148,577
2017	Wed, July 19	18	142,387
2018	Tue, August 28	17	147,042
2019	Fri, July 19	18	148,228
2020	Mon, July 20	17	141,449
2021	Tue, August 24	17	145,563
2022	Wed, July 20	18	144,356
2023	Thu, July 27	18	144,215
2024	Tue, July 16	18	148,890
2025	Mon, June 23	18	156,256

Forecasted Summer Peak Load for 2022 through 2027 as reported in the recent load forecast reports

	Forecasted Summer Peak Load (MW)					
Report	2022	2023	2024	2025	2026	2027
2022 Load Forecast	148,938	149,351	150,309	151,165	152,259	152,322
2023 Load Forecast		149,059	149,737	150,924	152,736	154,275
2024 Load Forecast			151,247	153,493	156,803	159,859
2025 Load Forecast				154,144	158,937	164,186

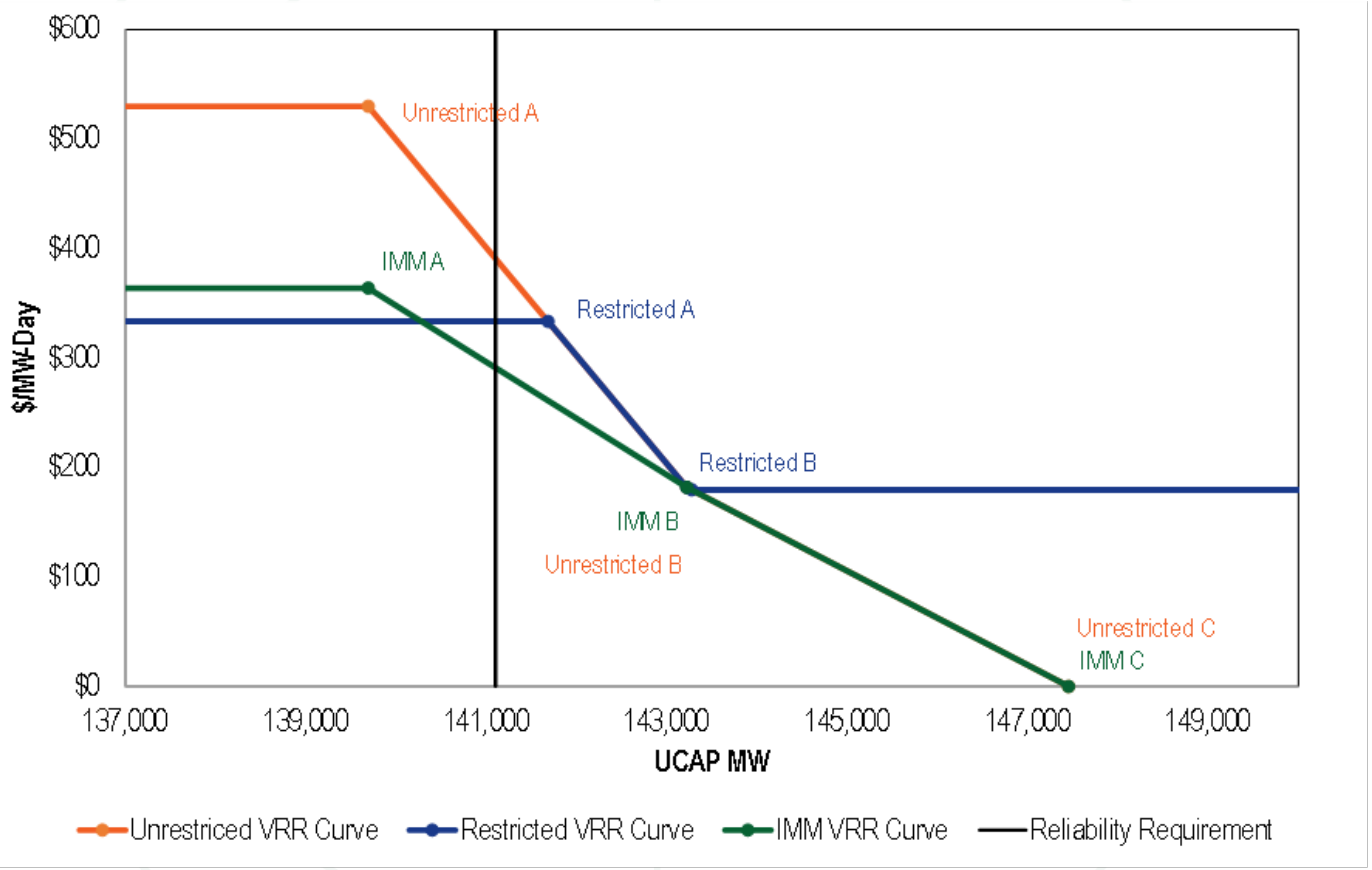
Large load adjustments for 2022 through 2027 as reported in the recent load forecast reports

	Large Load (MW)					
Report	2022	2023	2024	2025	2026	2027
2022 Load Forecast (Adjustments)	897	1,643	2,344	3,061	3,885	4,166
2023 Load Forecast (Adjustments Above Embedded)		2,231	3,393	4,654	6,594	8,300
2024 Load Forecast (Adjustments Above Embedded)			2,664	4,673	7,557	10,064
2025 Load Forecast (Adjustments Above Embedded)				3,591	8,453	13,668

Embedded and above embedded data center load for 2025/2026 RPM BRA, 2026/2027 RPM BRA and 2027/2028 RPM BRA

	Above Embedded	Embedded and Above Embedded
2025/2026 RPM BRA (Based on 2024 Load Forecast)	4,654	7,927
2026/2027 RPM BRA (Based on 2025 Load Forecast)	7,892	11,993
2027/2028 RPM BRA (Based on 2025 Load Forecast)	13,018	17,071

Comparison of VRR curves for RTO

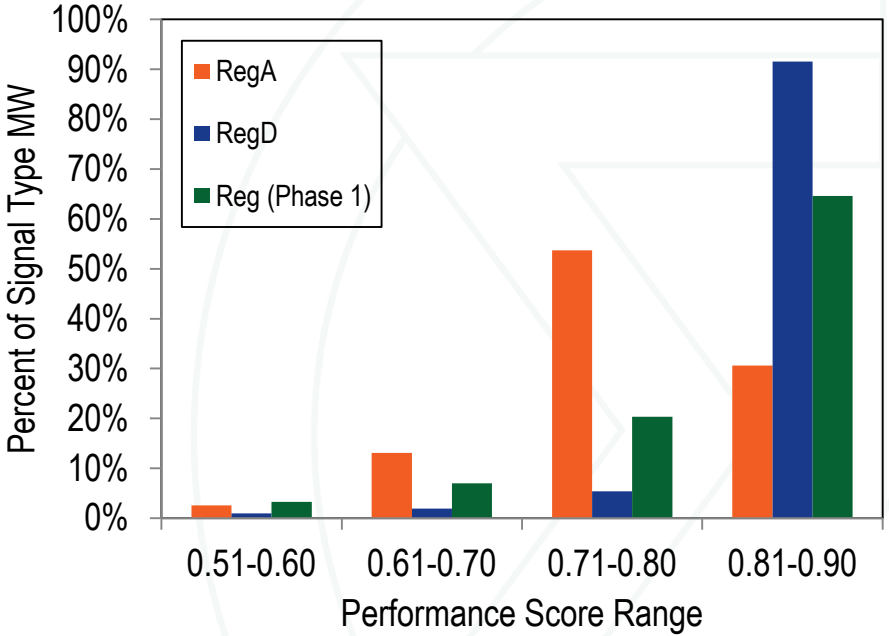


REGULATION MARKET

Regulation Market Redesign

- **Phase 1 went live on October 1, 2025, and included several substantial changes to the regulation market.**
  - **Replaced the RegA/RegD signals with a single signal and product; no longer a benefit factor to equate effective MW.**
  - **Performance score calculation simplified: removed the accuracy and delay components.**
  - **LOC calculation has been modified to account for ramp rate limitations of units.**
    - Tracks what each unit would have done in the energy market, based on their ramp capabilities.

Regulation Performance Scores



Month	Signal	Unit Type	Precision Score Range 61-70	71-80	81-90	91-100
Jan-Sep	RegA	Battery	7.3%	15.8%	26.8%	31.7%
		CT	9.2%	10.5%	16.2%	16.1%
		Diesel	4.0%	15.7%	26.4%	48.8%
		DSR	8.1%	7.7%	18.9%	23.2%
		Hydro	9.2%	13.7%	27.2%	30.4%
		Steam	10.1%	12.2%	15.0%	13.7%
	RegD	Battery	3.3%	9.1%	29.8%	52.7%
		CT	8.3%	19.8%	8.4%	4.1%
		Diesel	18.6%	33.7%	18.4%	10.9%
		DSR	3.3%	8.4%	26.4%	50.4%
		Hydro	-	-	-	-
		Steam	-	-	-	-
Oct-Dec	Reg (Phase 1)	Battery	1.3%	2.0%	4.9%	89.0%
		CT	3.2%	8.8%	36.9%	45.7%
		Diesel	0.4%	1.6%	21.5%	75.8%
		DSR	2.6%	3.2%	5.0%	82.3%
		Hydro	2.6%	7.3%	31.6%	56.0%
		Steam	4.6%	9.8%	24.6%	54.8%

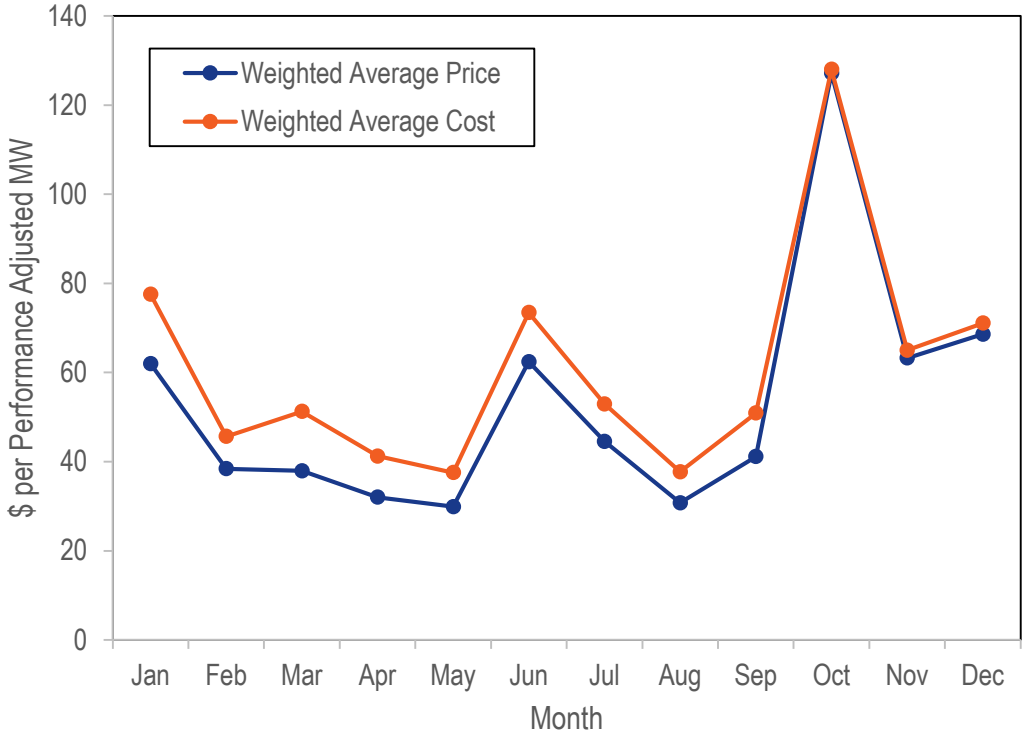
- Phase 1 performance scores are based on a modified version of the previous design's precision score.
- Error calculation includes an assigned regulation term (AReg) in the denominator that favors larger units.

$$Error = Avg\ of\ Abs\left|\frac{Abs\left(Response_{10sec} - Signal_{10sec}\right)}{0.5 * IntervalSignal_{AvgAbs} + 0.5 * AReg}\right|$$

Monitoring Analytics

Regulation Price and Cost

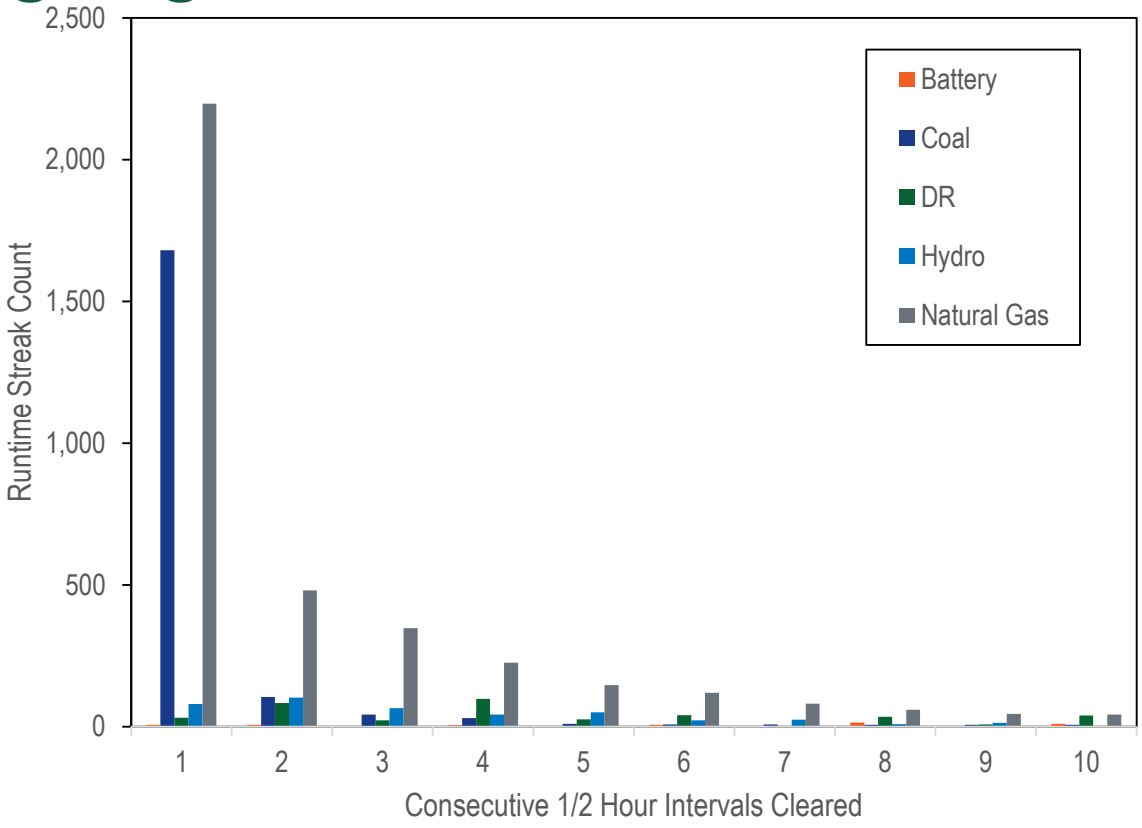
- **Price and cost were expected to increase due to inclusion of LOC inclusion in clearing prices.**
- **Due to an error in the clearing engine, there was a significant increase in the price and cost of regulation at the launch of phase 1.**
- **Weighted average price increased 202% in October compared to the average price in the first three quarters of 2025.**
- **Weighted average cost (price and shoulder LOC) in October increased 146% relative to the average cost from the first three quarters of 2025.**



Monitoring Analytics

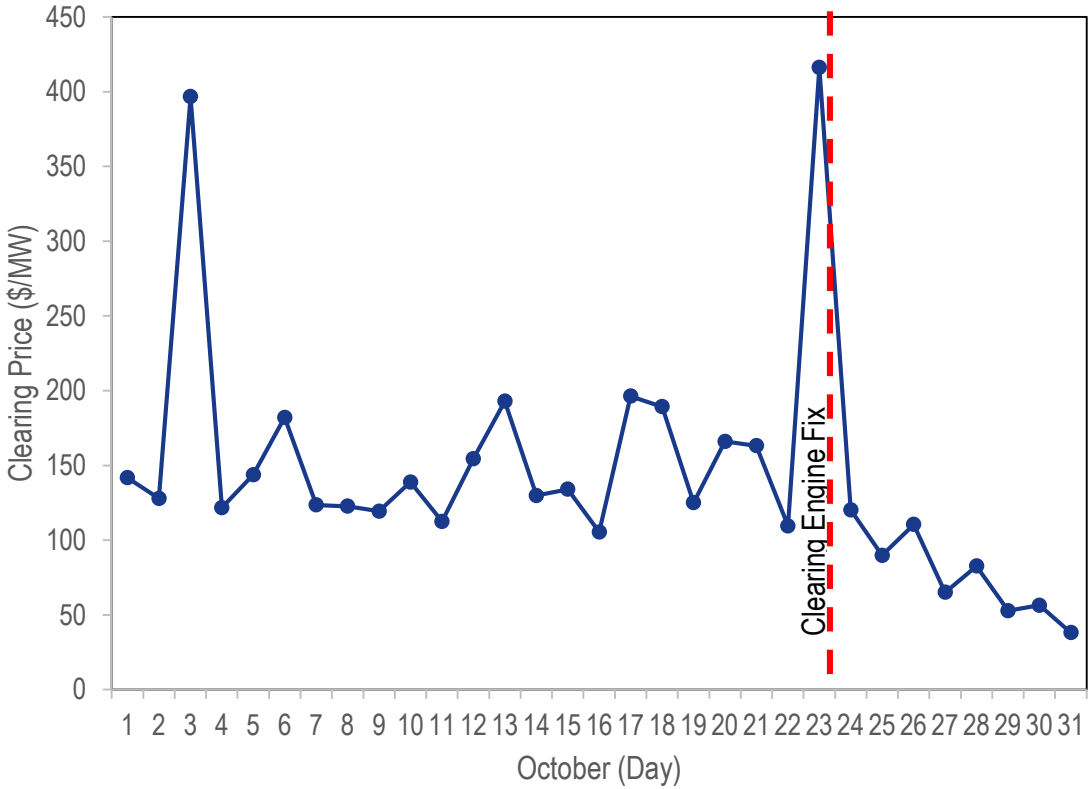
Phase 1 Clearing Engine Error: October 1-23

- Figure shows continuous runtimes for each unit type from October 1-23.
- PJM clearing engine assumed ramp rate used to provide regulation was not available for the next clearing interval.
- Coal and natural gas units were frequently eliminated from the market solution after one half hour interval.
- Error resulted in a reduction in supply that inflated prices in October.



Monitoring Analytics

October 2025 Daily Weighted Average Prices



- **Fix for the clearing engine was implemented on October 23, 2025.**
  - **From Oct. 1-23, daily weighted average prices averaged $166.**
  - **From Oct. 24-31, daily weighted average prices averaged $77.**

Monitoring Analytics

2025 Weighted Average Price and Cost

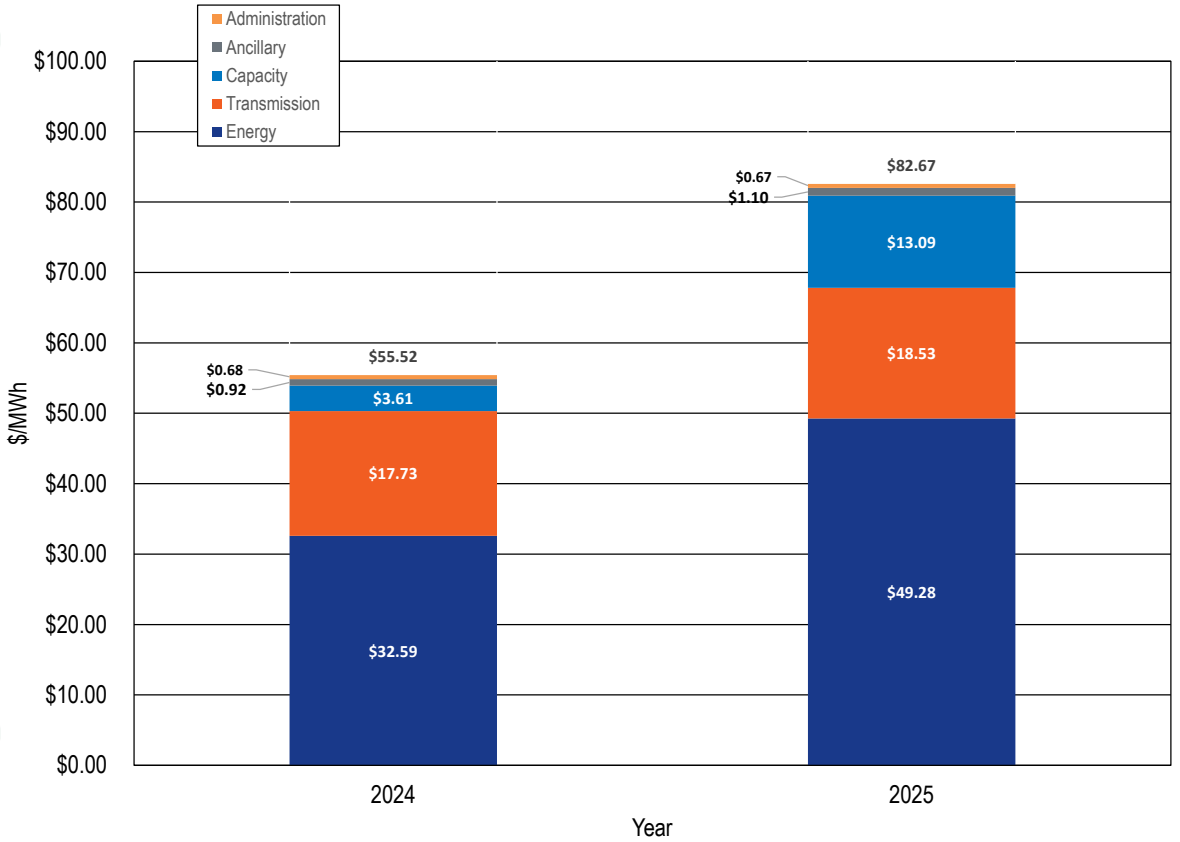
Month	Performance Adjusted MW	Total Regulation Credits ($)	Weighted Average Price ($/MW)	Weighted Average Cost ($/MW)	Price Percent of Cost
Jan	405,434.3	31,451,421	61.99	77.57	79.9%
Feb	357,640.4	16,335,357	38.41	45.68	84.1%
Mar	376,469.6	19,303,608	37.93	51.28	74.0%
Apr	367,193.0	15,142,726	32.02	41.24	77.6%
May	383,116.9	14,388,435	29.91	37.56	79.6%
Jun	404,541.1	29,706,971	62.43	73.43	85.0%
Jul	420,570.5	22,269,279	44.56	52.95	84.1%
Aug	406,661.9	15,348,773	30.77	37.74	81.5%
Sep	367,465.3	18,702,046	41.13	50.89	80.8%
Oct	472,430.6	60,069,077	127.15	127.99	99.3%
Nov	484,604.8	30,657,288	63.26	65.02	97.3%
Dec	465,183.7	31,910,381	68.60	71.09	96.5%

- **Average regulation credits increased over Q1-Q3 2025 average:**
- **196% in October.**
- **51% in November.**
- **57% in December.**

Monitoring Analytics

YEAR TO YEAR UPDATE

Total Cost of Wholesale Power



Monitoring Analytics

Total Cost of Wholesale Power – 2024/2025

Category	2024 $/MWh	2024 ($ Millions)	2024 Percent of Total	2025 $/MWh	2025 ($ Millions)	2025 Percent of Total	Percent Change
Energy	$32.59	$25,553	58.7%	$49.28	$39,959	59.6%	51.2%
Day Ahead Energy	$33.43	$26,215	60.2%	$50.16	$40,673	60.7%	50.0%
Balancing Energy	$0.57	$444	1.0%	$1.02	$824	1.2%	79.6%
ARR Credits	($1.24)	($970)	(2.2%)	($1.59)	($1,287)	(1.9%)	28.3%
Self Scheduled FTR Credits	($0.52)	($410)	(0.9%)	($1.31)	($1,061)	(1.6%)	150.0%
Balancing Congestion	$0.39	$304	0.7%	$0.58	$469	0.7%	49.2%
Emergency Energy	$0.00	$0	0.0%	$0.01	$6	0.0%	0.0%
Inadvertent Energy	$0.01	$9	0.0%	($0.01)	($10)	(0.0%)	(200.3%)
Load Response - Energy	$0.01	$11	0.0%	$0.03	$26	0.0%	116.9%
Emergency Load Response	$0.00	$0	0.0%	$0.08	$61	0.1%	0.0%
Energy Uplift (Operating Reserves)	$0.34	$268	0.6%	$0.94	$764	1.1%	175.7%
Marginal Loss Surplus Allocation	($0.45)	($357)	(0.8%)	($0.73)	($592)	(0.9%)	60.5%
Market to Market Payments	$0.05	$38	0.1%	$0.11	$86	0.1%	117.5%
Capacity	$3.61	$2,834	6.5%	$13.09	$10,616	15.8%	262.3%
Capacity (Capacity Market and FRR)	$3.56	$2,791	6.4%	$12.94	$10,490	15.6%	263.4%
Capacity Part V (RMR)	$0.04	$34	0.1%	$0.13	$108	0.2%	207.4%
Load Response - Capacity	$0.01	$8	0.0%	$0.02	$18	0.0%	116.8%
Transmission	$17.73	$13,900	31.9%	$18.53	$15,024	22.4%	4.5%
Transmission Service Charges	$15.04	$11,797	27.1%	$15.73	$12,753	19.0%	4.5%
Transmission Enhancement Cost Recovery	$2.59	$2,032	4.7%	$2.71	$2,194	3.3%	4.4%
Transmission Owner (Schedule 1A)	$0.09	$72	0.2%	$0.09	$77	0.1%	3.1%
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.92	$721	1.7%	$1.10	$894	1.3%	20.0%
Reactive	$0.48	$377	0.9%	$0.44	$358	0.5%	(8.2%)
Regulation	$0.23	$182	0.4%	$0.38	$309	0.5%	64.0%
Black Start	$0.09	$74	0.2%	$0.06	$51	0.1%	(33.3%)
Synchronized Reserves	$0.10	$75	0.2%	$0.19	$151	0.2%	95.9%
Secondary Reserves	$0.00	$2	0.0%	$0.01	$8	0.0%	266.4%
Non-Synchronized Reserves	$0.01	$10	0.0%	$0.02	$16	0.0%	53.1%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.68	$531	1.2%	$0.67	$546	0.8%	(0.6%)
PJM Administrative Fees	$0.63	$491	1.1%	$0.62	$505	0.8%	(0.5%)
NERC/RFC	$0.04	$34	0.1%	$0.05	$37	0.1%	3.9%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.01	$5	0.0%	$0.00	$4	0.0%	(36.2%)
Total Price	$55.52	$43,538	100.0%	$82.67	$67,039	100.0%	48.9%
Total Day Ahead Load (GWh)	775,838			800,515			3.2%
Total Balancing Load (GWh)	(8,344)			(10,378)			24.4%
Total Real Time Load (GWh)	784,182			810,894			3.4%
Total Cost ($ Billions)	$43.54			$67.04			54.0%

Total Cost of Wholesale Power – 2025 Monthly

- **Monthly cost of capacity exceeded monthly cost of transmission in June through December, 2025.**
- **First time that capacity costs have exceeded transmission costs since transmission costs first exceeded capacity costs in 2019.**
- **Result of higher capacity market prices for 2025/2026 Delivery Year.**

Total Cost of Wholesale Power – 2025 Monthly

- For the period from January through May:
  - Energy costs averaged 64.4 percent of the monthly total.
  - Capacity costs averaged 5.4 percent of the monthly total.
  - Transmission costs averaged 27.6 percent of the monthly total.
- For the period from June through December:
  - Energy costs averaged 55.0 percent of the monthly total.
  - Capacity costs averaged 22.2 percent of the monthly total.
  - Transmission costs averaged 20.8 percent of the monthly total.

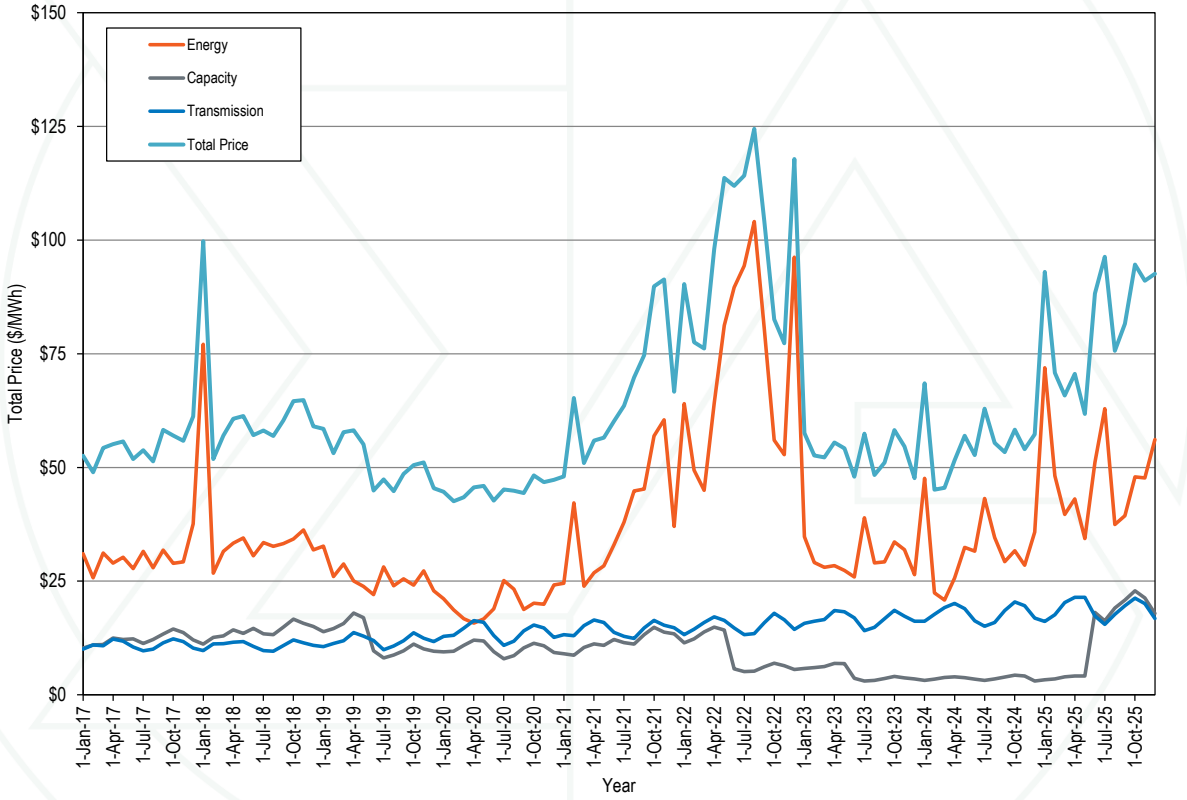
Total Cost of Wholesale Power – 2025 Monthly

Category	Jan $/MWh	Feb $/MWh	Mar $/MWh	Apr $/MWh	May $/MWh	Jun $/MWh	Jul $/MWh	Aug $/MWh	Sep $/MWh	Oct $/MWh	Nov $/MWh	Dec $/MWh
Energy	$71.90	$48.15	$39.66	$43.09	$34.35	$51.09	$62.92	$37.44	$39.41	$47.94	$47.70	$56.15
Day Ahead Energy	$66.89	$48.26	$40.37	$43.74	$36.98	$52.00	$65.90	$39.02	$40.74	$50.58	$49.45	$57.31
Balancing Energy	$1.45	$1.08	$0.66	$0.94	$0.62	$2.01	$1.19	$0.47	$0.87	$0.82	$0.72	$1.08
ARR Credits	($1.04)	($1.22)	($1.29)	($1.39)	($1.34)	($1.79)	($1.74)	($1.84)	($1.81)	($2.06)	($1.95)	($1.59)
Self Scheduled FTR Credits	($1.29)	($0.32)	($1.07)	($1.04)	($2.16)	($1.71)	($2.24)	($0.44)	($1.18)	($2.15)	($0.84)	($1.17)
Balancing Congestion	$1.70	$0.33	$0.72	$0.42	$0.27	$0.86	$0.20	$0.36	$0.40	$0.53	$0.42	$0.56
Emergency Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Inadvertent Energy	($0.01)	($0.01)	($0.02)	($0.02)	($0.03)	($0.01)	$0.00	$0.01	($0.02)	($0.02)	($0.01)	($0.01)
Load Response - Energy	$0.01	$0.00	$0.09	$0.04	$0.10	$0.00	$0.04	$0.03	$0.03	$0.03	$0.01	$0.02
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.56	$0.40	$0.02	$0.00
Energy Uplift (Operating Reserves)	$5.07	$0.53	$0.56	$0.71	$0.33	$0.52	$0.58	$0.37	$0.27	$0.34	$0.53	$0.68
Marginal Loss Surplus Allocation	($1.06)	($0.59)	($0.54)	($0.51)	($0.50)	($0.88)	($1.02)	($0.52)	($0.53)	($0.76)	($0.73)	($0.90)
Market to Market Payments	$0.19	$0.09	$0.17	$0.20	$0.06	$0.01	$0.02	($0.02)	$0.09	$0.24	$0.09	$0.18
Capacity	$3.33	$3.49	$3.96	$4.14	$4.16	$18.12	$16.30	$19.07	$20.84	$22.87	$21.31	$17.88
Capacity (Capacity Market and FRR)	$3.11	$3.36	$3.96	$4.14	$4.16	$18.15	$16.22	$18.60	$20.54	$22.45	$21.06	$17.88
Capacity Part V (RMR)	$0.23	$0.13	$0.00	$0.00	$0.00	($0.02)	$0.08	$0.23	$0.30	$0.42	$0.25	$0.00
Load Response - Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.25	$0.00	$0.00	$0.00	$0.00
Transmission	$16.13	$17.63	$20.30	$21.46	$21.47	$17.33	$15.48	$17.71	$19.62	$21.26	$20.06	$16.77
Transmission Service Charges	$13.73	$14.74	$17.24	$18.16	$18.24	$14.70	$13.18	$15.09	$16.65	$18.13	$17.03	$14.25
Transmission Enhancement Cost Recovery	$2.31	$2.79	$2.97	$3.21	$3.13	$2.54	$2.20	$2.52	$2.87	$3.04	$2.94	$2.42
Transmission Owner (Schedule 1A)	$0.09	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10	$0.09	$0.09	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$1.00	$0.90	$1.18	$1.15	$1.05	$1.11	$1.02	$0.82	$1.02	$1.81	$1.24	$1.08
Reactive	$0.39	$0.46	$0.50	$0.52	$0.51	$0.42	$0.36	$0.41	$0.47	$0.48	$0.47	$0.38
Regulation	$0.40	$0.25	$0.31	$0.26	$0.24	$0.41	$0.27	$0.21	$0.29	$1.01	$0.51	$0.46
Black Start	$0.07	$0.08	$0.09	$0.08	$0.08	$0.05	$0.04	$0.05	$0.06	$0.06	$0.06	$0.05
Synchronized Reserves	$0.14	$0.09	$0.25	$0.25	$0.19	$0.21	$0.30	$0.12	$0.17	$0.20	$0.17	$0.14
Secondary Reserves	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.02	$0.01	$0.02	$0.01	$0.02
Non-Synchronized Reserves	$0.01	$0.01	$0.03	$0.03	$0.02	$0.00	$0.03	$0.01	$0.02	$0.03	$0.02	$0.02
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Administration	$0.60	$0.65	$0.75	$0.73	$0.75	$0.61	$0.58	$0.63	$0.69	$0.73	$0.72	$0.70
PJM Administrative Fees	$0.56	$0.61	$0.70	$0.68	$0.70	$0.56	$0.53	$0.58	$0.64	$0.69	$0.68	$0.63
NERC/RFC	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.07
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00
Total Price	$92.97	$70.82	$65.84	$70.57	$61.78	$88.26	$96.30	$75.66	$81.59	$94.62	$91.04	$92.58
Total Day Ahead Load (GWh)	77,617	64,784	61,400	56,635	58,352	69,898	81,672	72,152	62,679	59,624	61,234	74,467
Total Balancing Load (GWh)	(1,292)	(1,181)	(561)	(697)	(501)	(1,923)	(1,342)	(266)	(765)	(356)	(656)	(838)
Total Real Time Load (GWh)	78,909	65,965	61,961	57,332	58,853	71,822	83,014	72,418	63,444	59,980	61,890	75,305
Total Cost ($ Billions)	$7.34	$4.67	$4.08	$4.05	$3.64	$6.34	$7.99	$5.48	$5.18	$5.68	$5.63	$6.97

Total Cost of Wholesale Power – 2025 Monthly

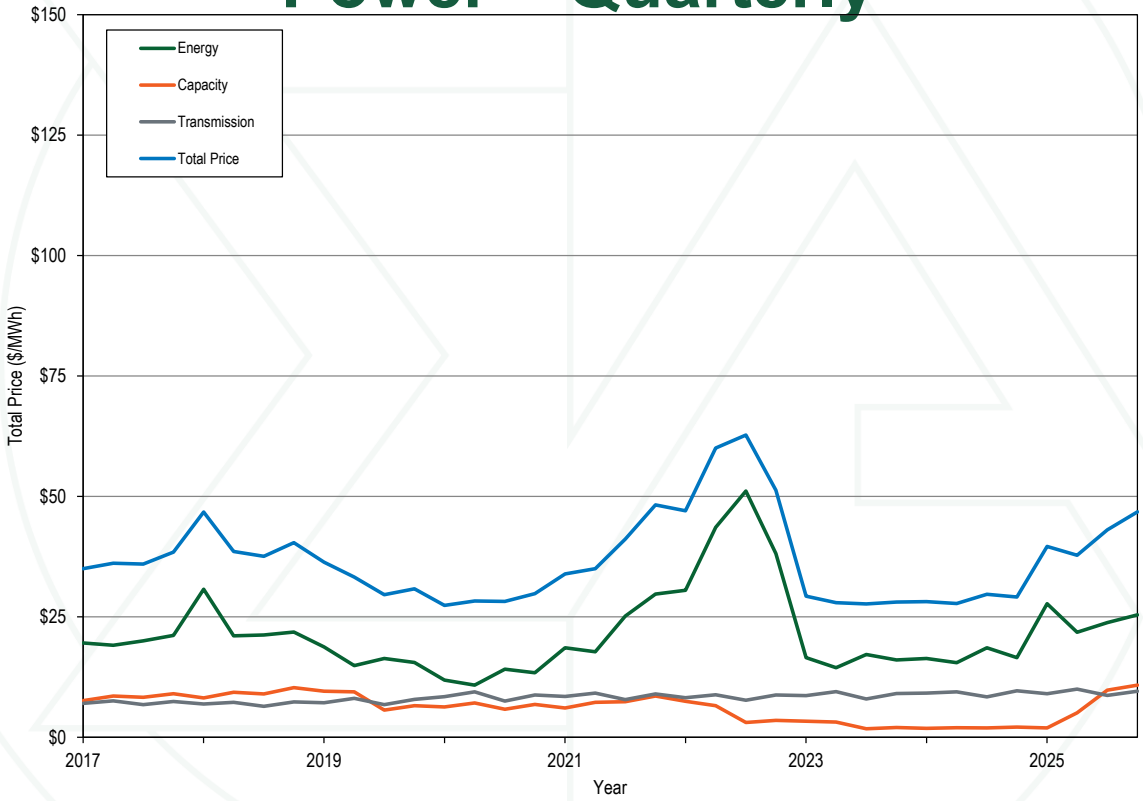
Category	Jan % of Total	Feb % of Total	Mar % of Total	Apr % of Total	May % of Total	Jun % of Total	Jul % of Total	Aug % of Total	Sep % of Total	Oct % of Total	Nov % of Total	Dec % of Total
Energy	77.3%	68.0%	60.2%	61.1%	55.6%	57.9%	65.3%	49.5%	48.3%	50.7%	52.4%	60.7%
Day Ahead Energy	71.9%	68.1%	61.3%	62.0%	59.9%	58.9%	68.4%	51.6%	49.9%	53.5%	54.3%	61.9%
Balancing Energy	1.6%	1.5%	1.0%	1.3%	1.0%	2.3%	1.2%	0.6%	1.1%	0.9%	0.8%	1.2%
ARR Credits	-1.1%	-1.7%	-2.0%	-2.0%	-2.2%	-2.0%	-1.8%	-2.4%	-2.2%	-2.2%	-2.1%	-1.7%
Self Scheduled FTR Credits	-1.4%	-0.5%	-1.6%	-1.5%	-3.5%	-1.9%	-2.3%	-0.6%	-1.4%	-2.3%	-0.9%	-1.3%
Balancing Congestion	1.8%	0.5%	1.1%	0.6%	0.4%	1.0%	0.2%	0.5%	0.5%	0.6%	0.5%	0.6%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Inadvertent Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Load Response - Energy	0.0%	0.0%	0.1%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.4%	0.0%	0.0%
Energy Uplift (Operating Reserves)	5.5%	0.7%	0.9%	1.0%	0.5%	0.6%	0.6%	0.5%	0.3%	0.4%	0.6%	0.7%
Marginal Loss Surplus Allocation	-1.1%	-0.8%	-0.8%	-0.7%	-0.8%	-1.0%	-1.1%	-0.7%	-0.6%	-0.8%	-0.8%	-1.0%
Market to Market Payments	0.2%	0.1%	0.3%	0.3%	0.1%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.2%
Capacity	3.6%	4.9%	6.0%	5.9%	6.7%	20.5%	16.9%	25.2%	25.5%	24.2%	23.4%	19.3%
Capacity (Capacity Market and FRR)	3.3%	4.7%	6.0%	5.9%	6.7%	20.6%	16.8%	24.6%	25.2%	23.7%	23.1%	19.3%
Capacity Part V (RMR)	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.4%	0.4%	0.3%	0.0%
Load Response - Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%
Transmission	17.3%	24.9%	30.8%	30.4%	34.8%	19.6%	16.1%	23.4%	24.0%	22.5%	22.0%	18.1%
Transmission Service Charges	14.8%	20.8%	26.2%	25.7%	29.5%	16.7%	13.7%	19.9%	20.4%	19.2%	18.7%	15.4%
Transmission Enhancement Cost Recovery	2.5%	3.9%	4.5%	4.5%	5.1%	2.9%	2.3%	3.3%	3.5%	3.2%	3.2%	2.6%
Transmission Owner (Schedule 1A)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.1%	1.3%	1.8%	1.6%	1.7%	1.3%	1.1%	1.1%	1.3%	1.9%	1.4%	1.2%
Reactive	0.4%	0.6%	0.8%	0.7%	0.8%	0.5%	0.4%	0.5%	0.6%	0.5%	0.5%	0.4%
Regulation	0.4%	0.4%	0.5%	0.4%	0.4%	0.5%	0.3%	0.3%	0.4%	1.1%	0.6%	0.5%
Black Start	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Synchronized Reserves	0.2%	0.1%	0.4%	0.4%	0.3%	0.2%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%
Secondary Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Administration	0.6%	0.9%	1.1%	1.0%	1.2%	0.7%	0.6%	0.8%	0.8%	0.8%	0.8%	0.8%
PJM Administrative Fees	0.6%	0.9%	1.1%	1.0%	1.1%	0.6%	0.6%	0.8%	0.8%	0.7%	0.7%	0.7%
NERC/RFC	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Total Cost of Wholesale Power – 2025 Monthly



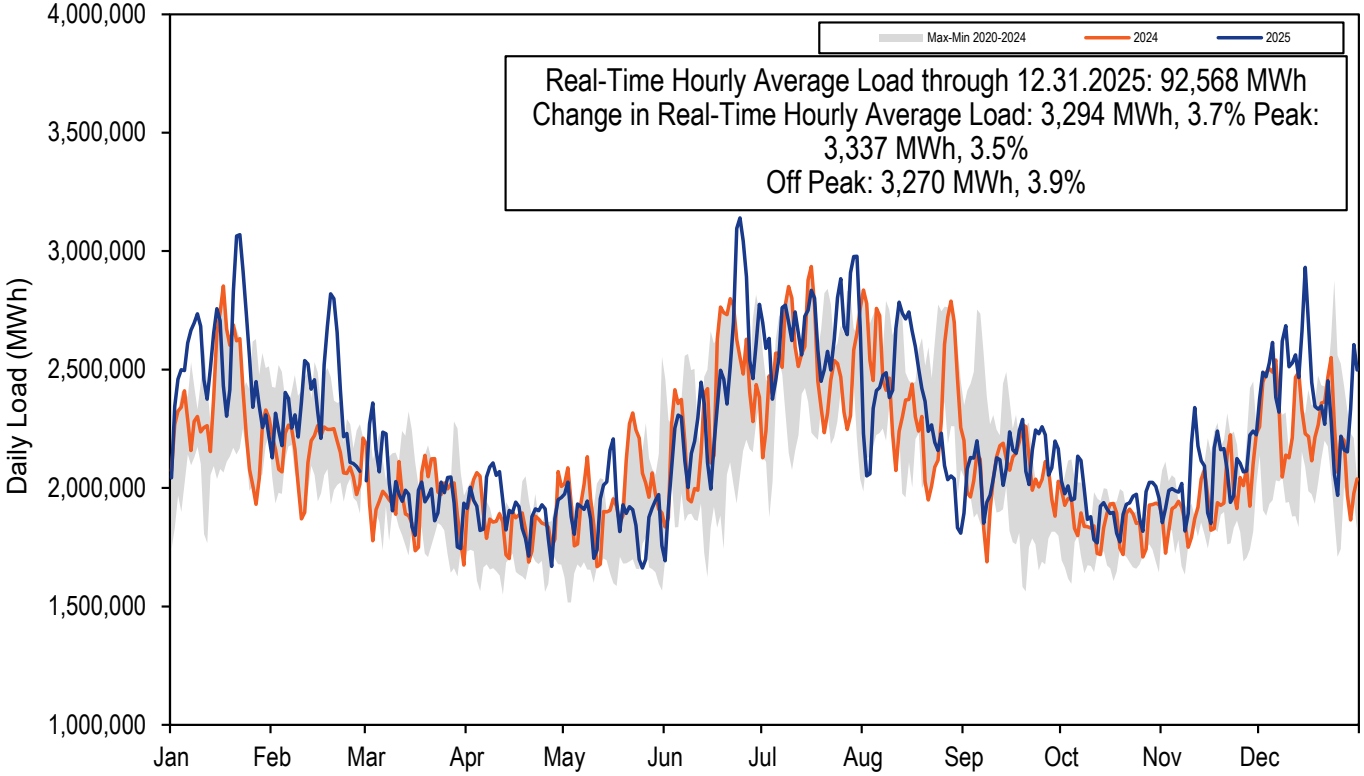
Monitoring Analytics

Inflation Adjusted Total Cost of Wholesale Power – Quarterly

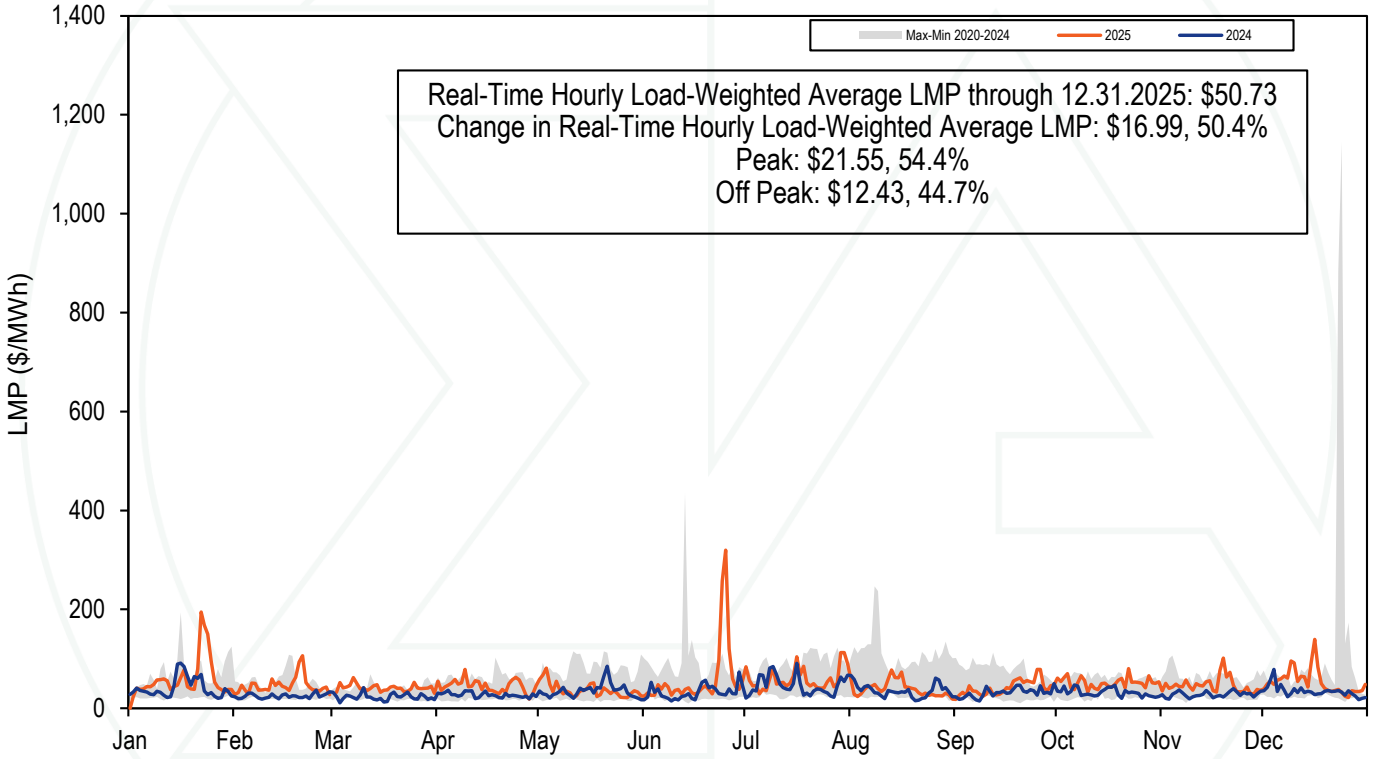


Monitoring Analytics

2025 PJM Real-Time Daily Load



2025 PJM Real-Time Daily LMP

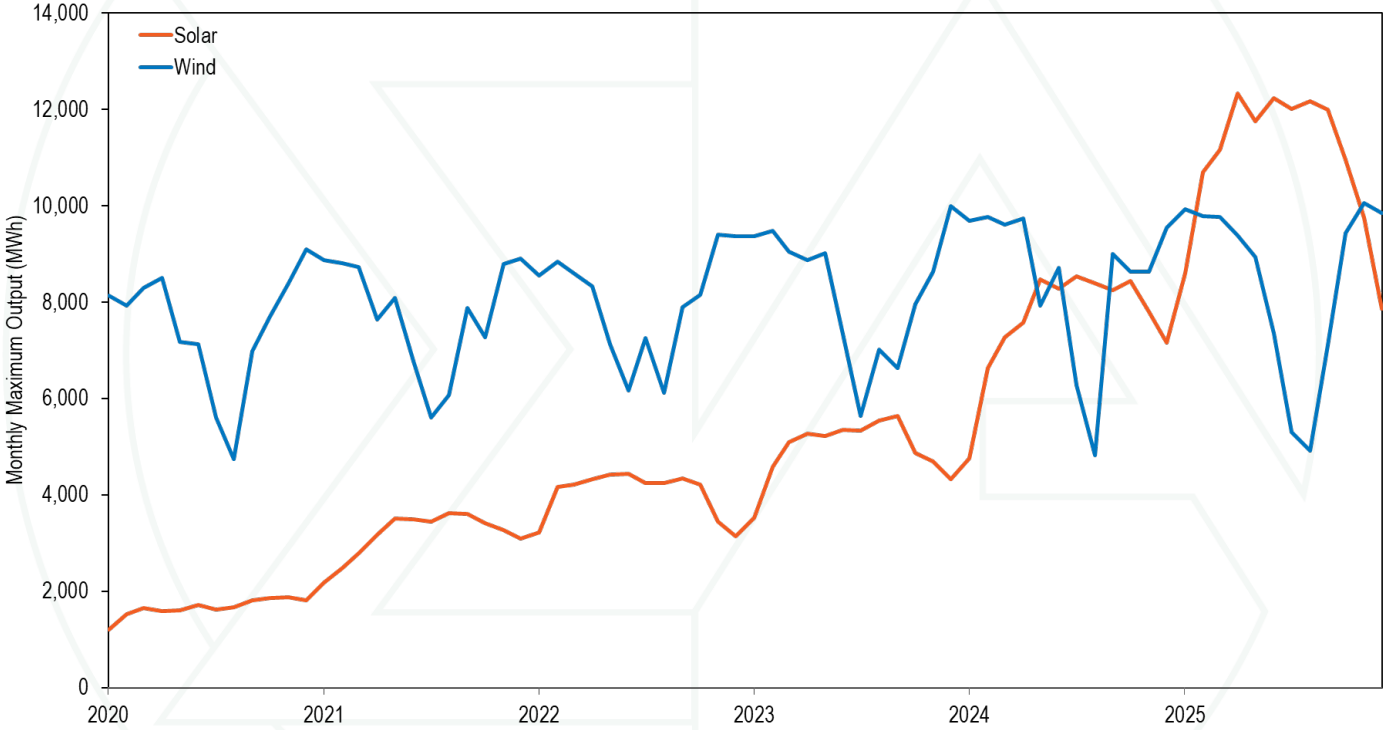


Monitoring Analytics

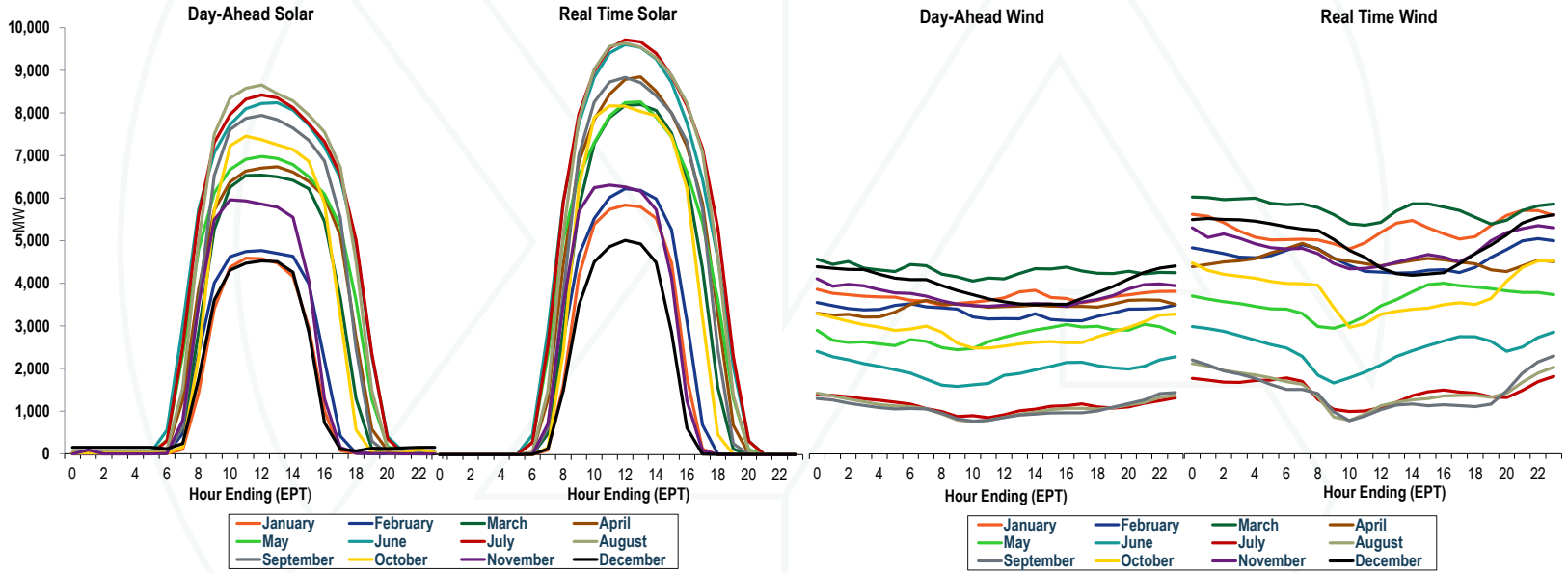
Annual Maximum Hourly Solar and Wind Output

	Solar Maximum Hourly Output			Solar Percent of	Wind Maximum Hourly Output			Wind Percent of
Year	Maximum Hourly MWh	Change	Percent Change	All Generation For The Year	Maximum Hourly MWh	Change	Percent Change	All Generation For The Year
2020	1,879			0.4%	9,095			3.3%
2021	3,617	1,739	92.5%	0.9%	8,911	(184)	(2.0%)	3.3%
2022	4,429	812	22.4%	1.1%	9,402	491	5.5%	3.8%
2023	5,630	1,201	27.1%	1.4%	9,993	592	6.3%	3.5%
2024	8,532	2,901	51.5%	2.1%	9,768	(226)	(2.3%)	3.7%
2025	12,325	3,794	44.5%	2.9%	10,058	290	3.0%	3.7%

Maximum Solar and Wind Hourly Output by Month



Average Hourly Solar & Wind MW: DA and RT

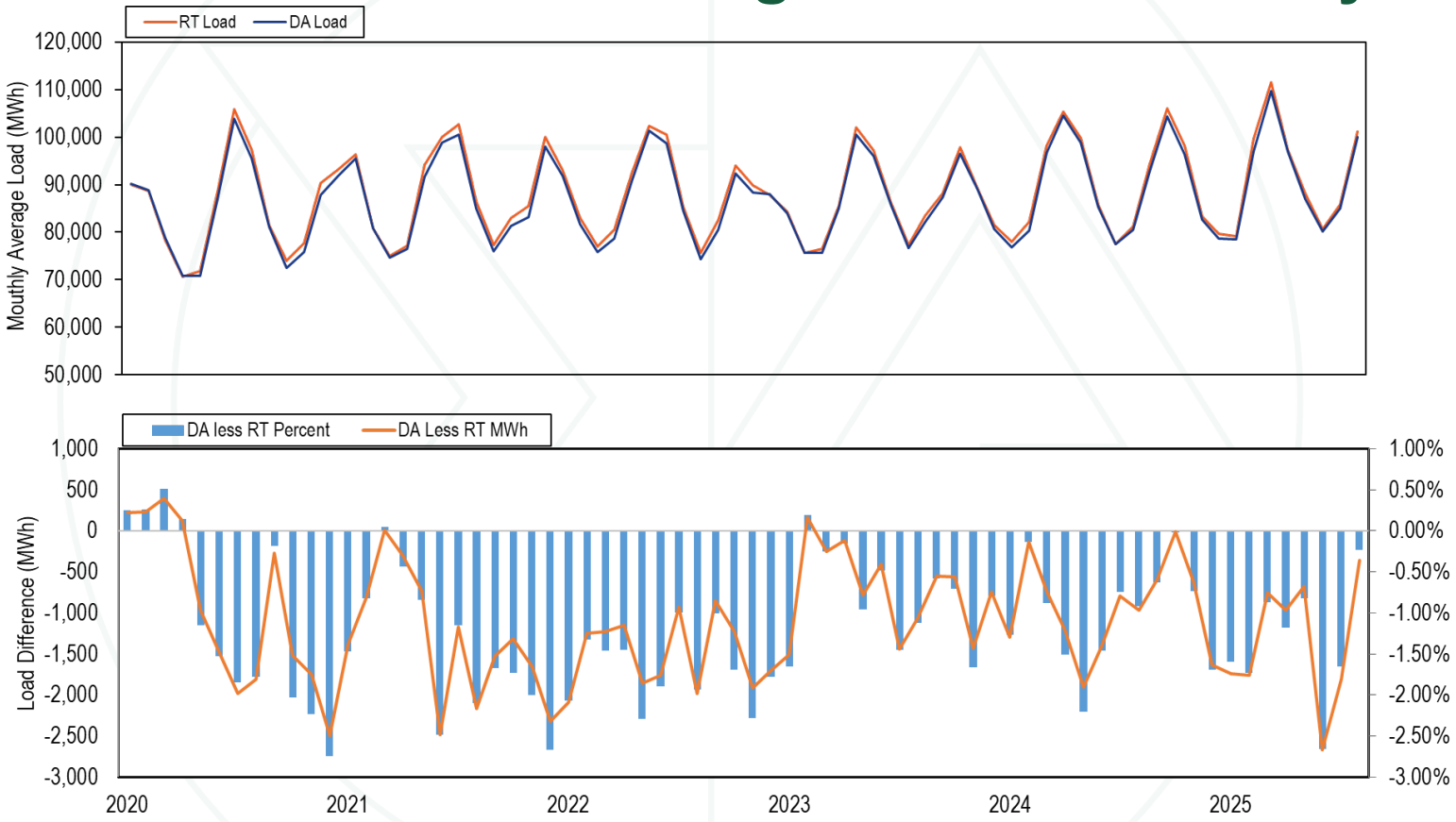


Monitoring Analytics

Real-Time Load-Weighted Average LMP

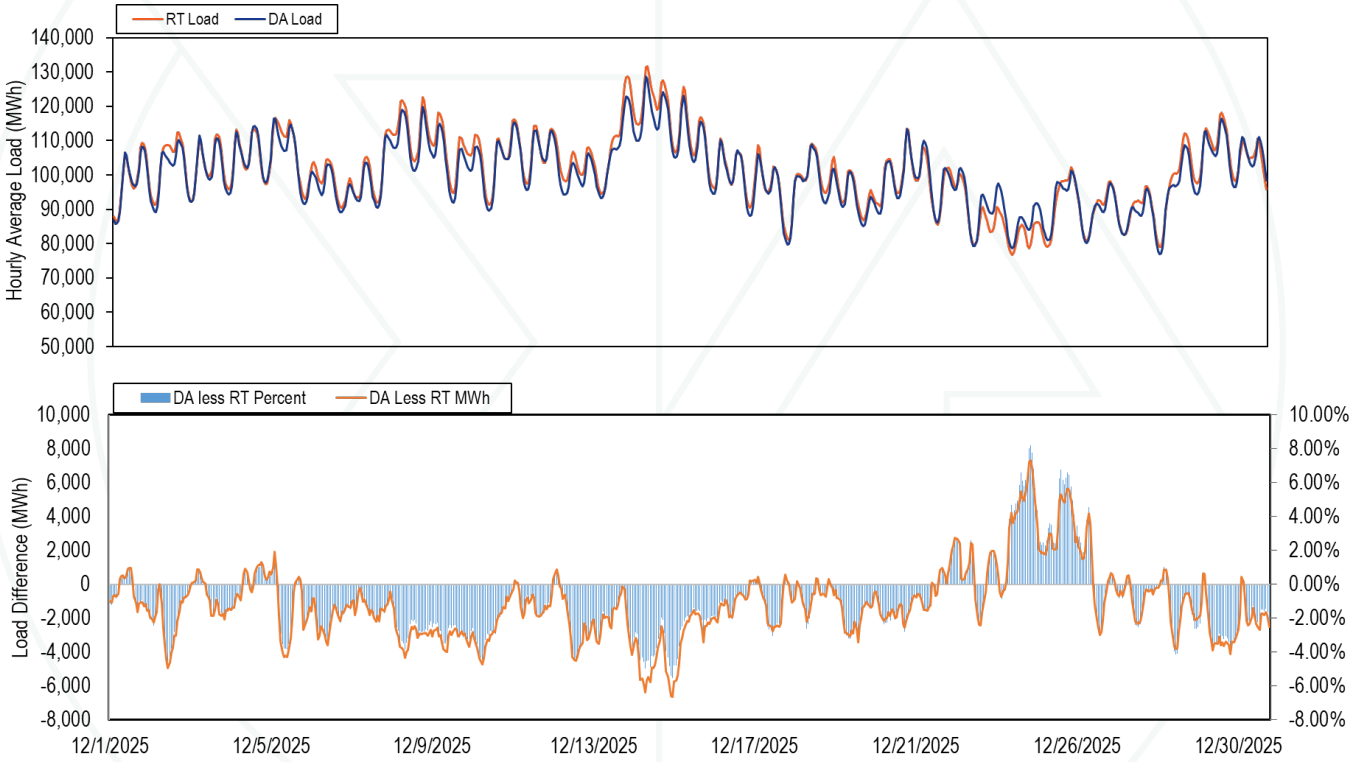
	2024				2025			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$38.50	$47.10	$8.60	22.3%	$55.29	$70.54	$15.25	27.6%
Feb	$24.49	$25.23	$0.74	3.0%	$43.75	$54.12	$10.37	23.7%
Mar	$21.64	$24.79	$3.15	14.6%	$38.89	$45.68	$6.79	17.5%
Apr	$23.99	$30.03	$6.04	25.2%	$38.15	$52.08	$13.93	36.5%
May	$28.99	$42.74	$13.75	47.4%	$27.32	$45.53	$18.21	66.7%
Jun	$26.66	$40.04	$13.38	50.2%	$39.62	$94.51	$54.89	138.5%
Jul	$32.20	$60.78	$28.58	88.7%	$39.08	$77.77	$38.68	99.0%
Aug	$26.71	$44.99	$18.28	68.5%	$29.15	$49.92	$20.77	71.2%
Sep	$24.53	$39.42	$14.89	60.7%	$34.41	$52.55	$18.14	52.7%
Oct	$26.60	$36.49	$9.89	37.2%	$41.55	$59.43	$17.88	43.0%
Nov	$23.80	$33.18	$9.38	39.4%	$40.52	$55.12	$14.59	36.0%
Dec	$31.60	$38.70	$7.10	22.5%	$49.92	$60.68	$10.76	21.6%

DA vs RT Load Bidding Difference History



Monitoring Analytics

DA vs RT Hourly Load Bidding Difference, December 2025



FAST START

Fast Start Pricing: DLMP and PLMP

- **PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021.**
- **The goal of fast start pricing is to allow inflexible resources to set prices based on the sum of their commitment costs per MWh and their marginal costs.**
- **The pricing run LMP (PLMP) is now the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP).**

Fast Start Pricing: DLMP and PLMP

- **Fast start pricing employs a new LMP calculation called the pricing run.**
- **The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously reducing ("relaxing" or ignoring) the economic minimum and maximum output MW constraints for all eligible fast start units.**

Fast Start Pricing: DLMP and PLMP

- **The price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin.**
- **The differences between the actual LMP (DLMP) and the fast start LMP (PLMP) distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions.**

Fast Start Pricing: DLMP and PLMP

- PJM also uses the pricing run for capping the system marginal price at $3,700 per MWh.
  - This was last used during Winter Storm Elliott.
  - The cap applies to the marginal energy component of LMP, but the congestion and loss components of LMP can exceed the cap.
- PJM uses a lower default transmission constraint penalty factor in the pricing run in the day-ahead market.
  - $30,000 per MWh in the dispatch run
  - $2,000 per MWh in the pricing run

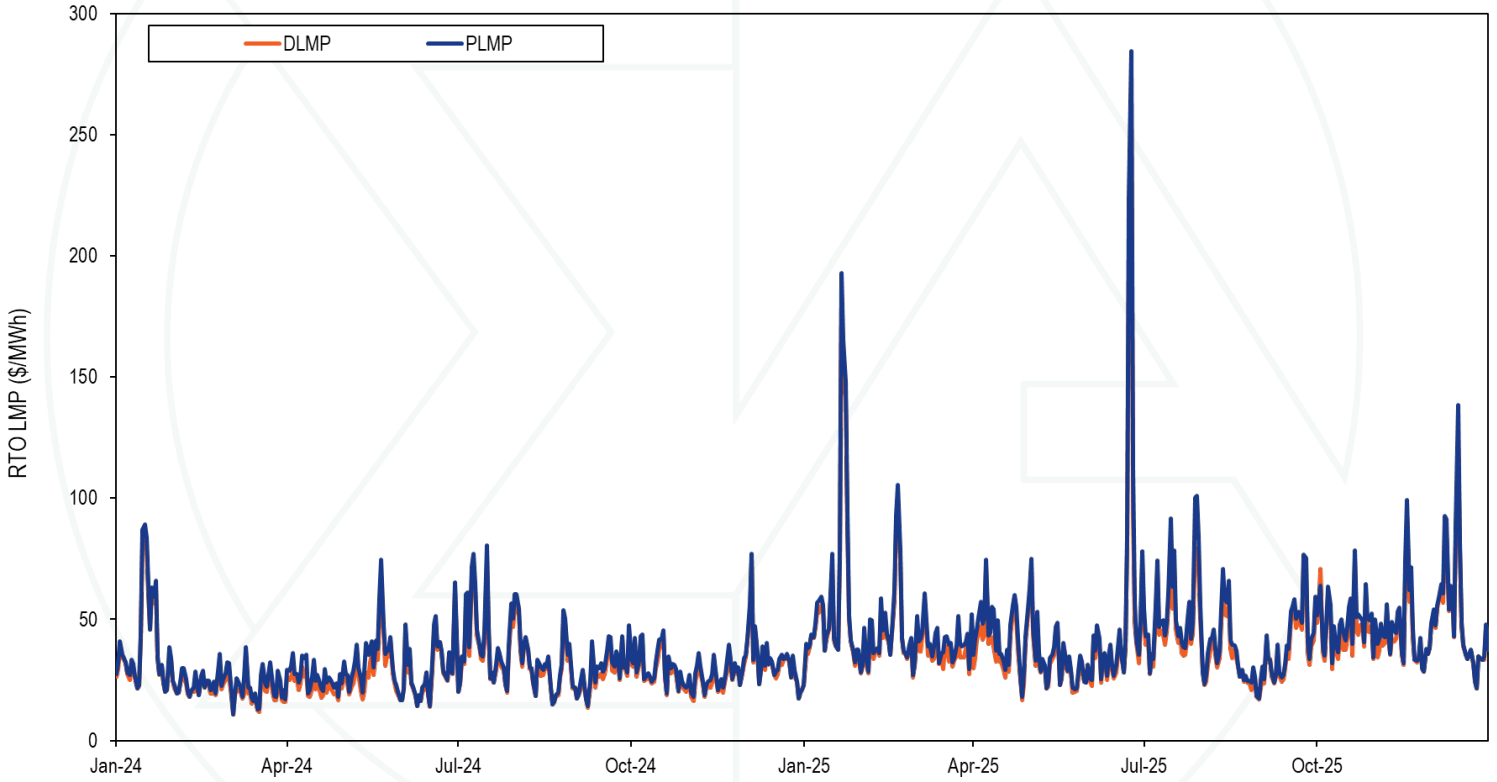
Monthly Average Load-Weighted DLMP and PLMP

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2024	Jan	$48.45	$48.65	$0.20	0.4%	$40.82	$42.78	$1.95	4.8%
2024	Feb	$23.67	$23.70	$0.03	0.1%	$23.20	$24.86	$1.66	7.2%
2024	Mar	$21.89	$21.93	$0.04	0.2%	$20.30	$23.15	$2.85	14.0%
2024	Apr	$26.73	$26.75	$0.02	0.1%	$23.29	$27.17	$3.87	16.6%
2024	May	$32.92	$32.90	($0.02)	(0.1%)	$31.70	$36.16	$4.46	14.1%
2024	Jun	$32.59	$32.62	$0.03	0.1%	$31.95	$33.35	$1.40	4.4%
2024	Jul	$44.51	$44.69	$0.18	0.4%	$44.12	$47.17	$3.04	6.9%
2024	Aug	$36.34	$36.31	($0.03)	(0.1%)	$34.37	$36.29	$1.92	5.6%
2024	Sep	$30.63	$30.77	$0.14	0.4%	$29.32	$31.81	$2.48	8.5%
2024	Oct	$33.18	$33.26	$0.08	0.2%	$29.85	$31.87	$2.02	6.8%
2024	Nov	$29.78	$29.82	$0.04	0.1%	$25.70	$28.26	$2.55	9.9%
2024	Dec	$36.98	$37.05	$0.06	0.2%	$33.62	$34.98	$1.36	4.0%
2024		$33.72	$33.79	$0.07	0.2%	$31.31	$33.74	$2.43	7.7%
2025	Jan	$67.53	$67.74	$0.21	0.3%	$59.93	$62.87	$2.94	4.9%
2025	Feb	$48.85	$49.02	$0.16	0.3%	$46.27	$48.90	$2.62	5.7%
2025	Mar	$40.76	$40.74	($0.03)	(0.1%)	$37.82	$42.11	$4.30	11.4%
2025	Apr	$44.36	$44.35	($0.01)	(0.0%)	$40.07	$45.42	$5.35	13.4%
2025	May	$37.56	$37.40	($0.16)	(0.4%)	$33.98	$36.34	$2.36	6.9%
2025	Jun	$53.01	$53.14	$0.13	0.2%	$62.53	$68.13	$5.60	9.0%
2025	Jul	$66.56	$66.76	$0.20	0.3%	$52.41	$59.38	$6.97	13.3%
2025	Aug	$39.24	$39.27	$0.03	0.1%	$35.97	$39.52	$3.55	9.9%
2025	Sep	$41.26	$41.24	($0.02)	(0.0%)	$40.49	$43.71	$3.22	7.9%
2025	Oct	$50.56	$50.73	$0.17	0.3%	$47.32	$51.01	$3.69	7.8%
2025	Nov	$49.70	$49.85	$0.15	0.3%	$43.82	$47.08	$3.26	7.4%
2025	Dec	$57.97	$58.08	$0.11	0.2%	$52.55	$55.29	$2.74	5.2%
2025		$59.01	$59.20	$0.19	0.3%	$53.71	$56.51	$2.80	5.2%

Real-Time Fast Start Impact

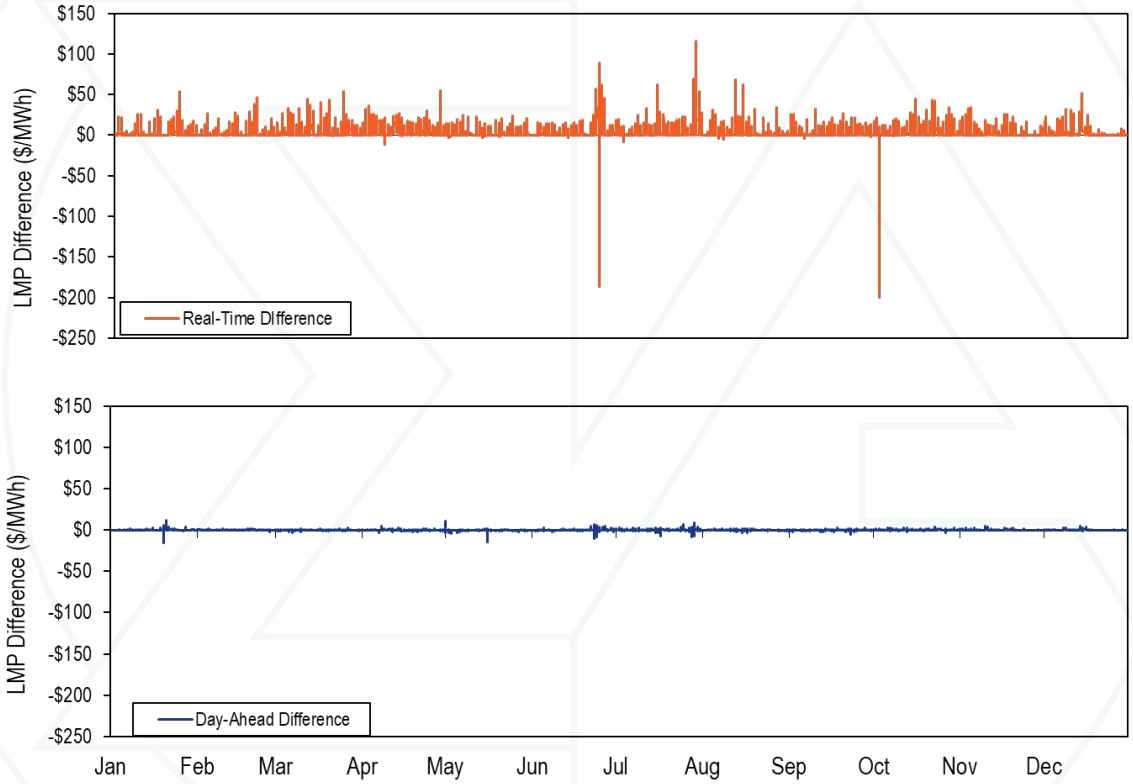
Month	2022 (In Millions)	2023 (In Millions)	2024 (In Millions)	2025 (In Millions)
Jan	$196.33	$72.89	$142.06	$232.11
Feb	$52.11	$33.74	$103.17	$173.03
Mar	$106.74	$53.11	$172.59	$266.16
Apr	$195.22	$121.28	$217.50	$306.90
May	$247.03	$143.80	$272.73	$138.96
Jun	$429.42	$98.31	$98.74	$402.22
Jul	$643.44	$217.56	$238.39	$578.75
Aug	$602.88	$112.21	$142.81	$257.33
Sep	$259.08	$137.94	$153.65	$95.35
Oct	$204.26	$239.25	$116.28	$221.30
Nov	$122.77	$152.91	$149.38	$201.99
Dec	-$99.68	$104.53	$95.35	$206.05
Total	$2,959.60	$1,487.52	$1,902.66	$3,080.15

Daily Average Real-Time DLMP and PLMP



Monitoring Analytics

Hourly Difference: PLMP – DLMP



Monitoring Analytics

Fast Start Units as a Percent of Marginal Units

		Dispatch Run					Pricing Run				
Year	Month	CT	Diesel	Wind	Solar	All Fast Start Units	CT	Diesel	Wind	Solar	All Fast Start Units
2024	Jan	0.7%	0.6%	0.0%	0.0%	1.3%	3.5%	1.1%	0.0%	0.0%	4.7%
2024	Feb	0.4%	0.1%	0.1%	0.0%	0.5%	2.2%	0.1%	0.1%	0.0%	2.4%
2024	Mar	0.7%	0.2%	1.2%	0.0%	2.1%	4.1%	0.8%	1.3%	0.0%	6.2%
2024	Apr	1.5%	0.2%	0.2%	0.0%	1.9%	6.5%	0.7%	0.1%	0.0%	7.3%
2024	May	0.6%	0.2%	0.1%	0.0%	1.0%	5.1%	0.6%	0.1%	0.0%	5.8%
2024	Jun	0.5%	0.3%	0.1%	0.0%	0.8%	3.5%	0.4%	0.1%	0.0%	4.0%
2024	Jul	0.8%	0.5%	0.0%	0.1%	1.4%	7.4%	1.0%	0.0%	0.1%	8.5%
2024	Aug	0.6%	0.5%	0.0%	0.0%	1.1%	5.0%	1.0%	0.0%	0.0%	6.0%
2024	Sep	1.0%	0.1%	0.0%	0.0%	1.1%	7.1%	0.4%	0.0%	0.0%	7.6%
2024	Oct	1.2%	0.1%	0.0%	0.0%	1.3%	6.4%	1.3%	0.0%	0.0%	7.7%
2024	Nov	1.0%	0.2%	0.0%	0.1%	1.4%	6.2%	0.6%	0.0%	0.1%	7.0%
2024	Dec	0.5%	0.2%	0.0%	0.0%	0.7%	2.2%	0.6%	0.0%	0.0%	2.9%
2024		0.8%	0.3%	0.2%	0.0%	1.2%	4.9%	0.7%	0.2%	0.0%	5.8%
2025	Jan	0.8%	0.6%	0.1%	0.0%	1.5%	4.5%	2.1%	0.1%	0.0%	6.8%
2025	Feb	1.5%	0.1%	0.4%	0.0%	2.0%	3.7%	0.6%	0.3%	0.0%	4.6%
2025	Mar	0.5%	4.5%	0.1%	0.2%	5.2%	3.4%	5.0%	0.1%	0.2%	8.6%
2025	Apr	1.9%	1.8%	0.3%	0.1%	4.1%	7.1%	2.2%	0.3%	0.1%	9.7%
2025	May	0.6%	0.3%	0.0%	0.0%	1.0%	3.9%	1.5%	0.0%	0.0%	5.4%
2025	Jun	1.4%	0.2%	0.0%	0.0%	1.6%	6.2%	0.8%	0.0%	0.0%	7.0%
2025	Jul	2.6%	0.6%	0.0%	0.0%	3.2%	11.2%	1.5%	0.0%	0.0%	12.8%
2025	Aug	2.2%	0.5%	0.0%	0.0%	2.7%	7.8%	1.1%	0.0%	0.0%	8.9%
2025	Sep	1.2%	0.4%	0.0%	0.0%	1.6%	5.7%	1.2%	0.0%	0.0%	6.9%
2025	Oct	1.4%	0.3%	0.2%	0.0%	1.8%	4.8%	0.6%	0.2%	0.0%	5.6%
2025	Nov	0.7%	0.5%	0.6%	0.0%	1.8%	3.8%	1.3%	0.5%	0.0%	5.7%
2025	Dec	1.8%	0.1%	0.1%	0.0%	1.9%	6.1%	0.6%	0.1%	0.0%	6.7%
2025		1.4%	0.8%	0.2%	0.0%	2.4%	5.7%	1.5%	0.1%	0.0%	7.4%

Fast Start Impacts: Zone Average Differences

	2025							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$34.56	$34.63	$0.07	0.2%	$32.04	$34.26	$2.22	6.9%
AEP	$38.41	$38.48	$0.07	0.2%	$35.35	$38.23	$2.88	8.2%
APS	$39.91	$39.97	$0.06	0.2%	$36.82	$39.85	$3.03	8.2%
ATSI	$38.62	$38.65	$0.03	0.1%	$35.02	$37.85	$2.83	8.1%
BGE	$48.64	$48.73	$0.09	0.2%	$44.39	$48.03	$3.64	8.2%
COMED	$31.01	$31.09	$0.08	0.3%	$28.19	$30.60	$2.41	8.5%
DAY	$39.47	$39.55	$0.07	0.2%	$35.93	$38.90	$2.97	8.3%
DUKE	$38.11	$38.18	$0.07	0.2%	$34.60	$37.46	$2.86	8.3%
DOM	$48.46	$48.51	$0.05	0.1%	$45.11	$48.40	$3.29	7.3%
DPL	$38.91	$39.02	$0.11	0.3%	$35.73	$39.01	$3.27	9.2%
DUQ	$37.45	$37.51	$0.06	0.2%	$34.44	$37.22	$2.78	8.1%
EKPC	$37.54	$37.61	$0.07	0.2%	$34.56	$37.40	$2.84	8.2%
JCPLC	$34.67	$34.74	$0.07	0.2%	$32.19	$34.46	$2.27	7.0%
MEC	$36.08	$36.15	$0.07	0.2%	$32.98	$35.45	$2.47	7.5%
OVEC	$36.75	$36.82	$0.07	0.2%	$33.35	$36.10	$2.75	8.2%
PECO	$33.95	$34.02	$0.07	0.2%	$31.52	$33.68	$2.16	6.8%
PE	$40.49	$40.53	$0.04	0.1%	$36.96	$39.75	$2.79	7.5%
PEPCO	$47.14	$47.22	$0.08	0.2%	$43.18	$46.63	$3.44	8.0%
PPL	$33.20	$33.27	$0.07	0.2%	$30.63	$32.92	$2.29	7.5%
PSEG	$35.08	$35.15	$0.07	0.2%	$32.98	$35.32	$2.33	7.1%
REC	$38.24	$38.31	$0.07	0.2%	$35.72	$38.20	$2.48	6.9%

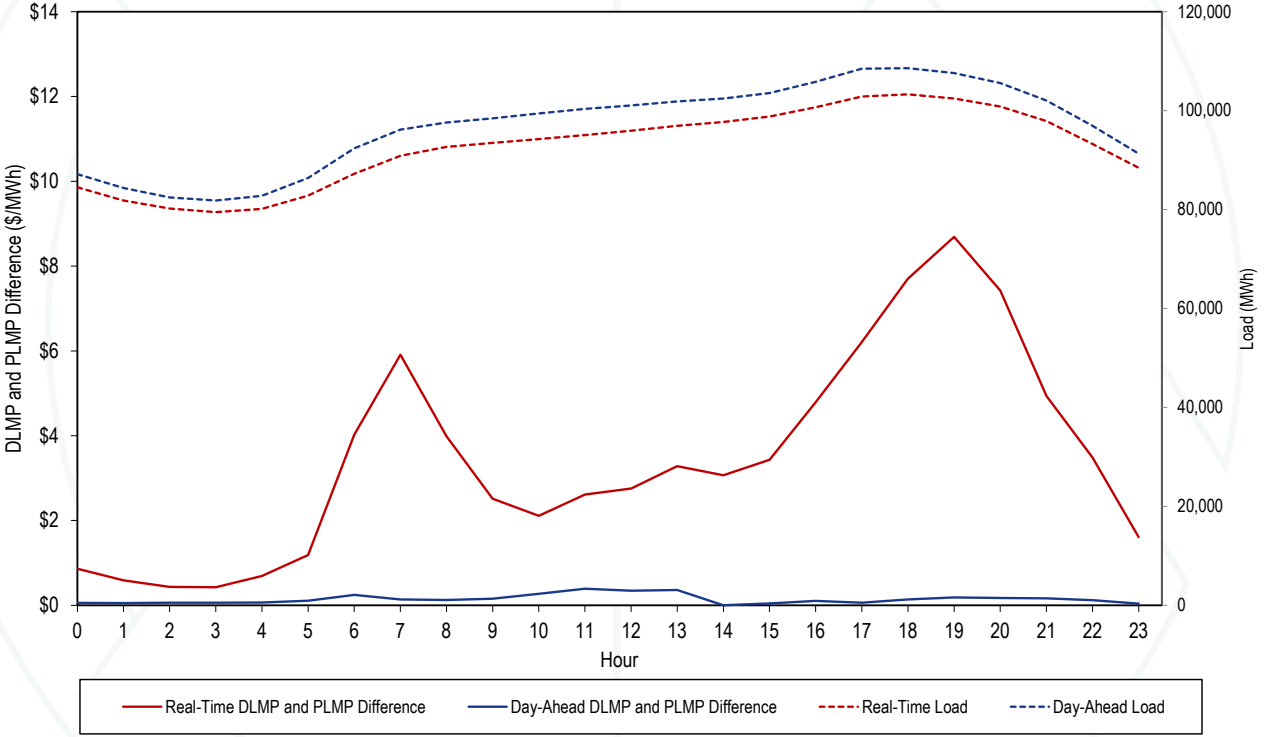
Fast Start Impacts: Hub Average Differences

	2025							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$36.57	$36.61	$0.05	0.1%	$33.21	$35.96	$2.75	8.3%
AEP-DAYTON HUB	$37.88	$37.92	$0.05	0.1%	$34.44	$37.27	$2.83	8.2%
ATSI GEN HUB	$38.00	$38.02	$0.02	0.1%	$34.22	$36.97	$2.76	8.1%
CHICAGO GEN HUB	$30.27	$30.35	$0.08	0.3%	$27.18	$29.61	$2.43	8.9%
CHICAGO HUB	$31.18	$31.22	$0.04	0.1%	$28.26	$30.67	$2.41	8.5%
DOMINION HUB	$42.42	$42.46	$0.04	0.1%	$39.16	$42.31	$3.15	8.0%
EASTERN HUB	$38.54	$38.62	$0.08	0.2%	$35.19	$38.37	$3.17	9.0%
N ILLINOIS HUB	$30.96	$31.05	$0.09	0.3%	$28.23	$30.64	$2.41	8.5%
NEW JERSEY HUB	$34.85	$34.90	$0.05	0.1%	$32.53	$34.82	$2.29	7.0%
OHIO HUB	$37.90	$37.95	$0.05	0.1%	$34.48	$37.31	$2.83	8.2%
WEST INT HUB	$39.69	$39.72	$0.03	0.1%	$36.33	$39.25	$2.92	8.0%
WESTERN HUB	$41.98	$42.03	$0.04	0.1%	$38.20	$41.24	$3.04	8.0%

Zonal Real-Time PLMP-DLMP Difference Frequency

	2025									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	1.0%	46.2%	41.6%	7.2%	3.3%	0.5%	0.1%	0.0%
ACEC	0.0%	0.1%	5.0%	46.4%	39.7%	5.6%	2.7%	0.5%	0.1%	0.0%
AEP	0.0%	0.0%	1.6%	46.3%	40.8%	7.3%	3.3%	0.6%	0.1%	0.0%
APS	0.0%	0.0%	1.2%	46.3%	40.7%	7.3%	3.7%	0.6%	0.1%	0.0%
ATSI	0.0%	0.0%	1.8%	46.2%	40.8%	7.1%	3.3%	0.6%	0.1%	0.0%
BGE	0.0%	0.1%	2.6%	46.1%	37.7%	7.5%	4.6%	1.1%	0.2%	0.0%
COMED	0.1%	0.1%	5.1%	47.1%	37.9%	6.3%	2.7%	0.5%	0.1%	0.0%
DAY	0.0%	0.1%	1.8%	46.4%	40.4%	7.3%	3.4%	0.6%	0.1%	0.0%
DUKE	0.0%	0.1%	1.8%	46.4%	40.6%	7.2%	3.3%	0.6%	0.1%	0.0%
DOM	0.1%	0.3%	2.3%	46.2%	38.7%	7.2%	4.2%	0.9%	0.2%	0.0%
DPL	0.0%	0.1%	6.2%	46.3%	37.4%	5.3%	2.7%	1.0%	0.8%	0.0%
DUQ	0.0%	0.0%	1.9%	46.3%	40.9%	7.0%	3.2%	0.5%	0.1%	0.0%
EKPC	0.0%	0.0%	1.8%	46.3%	40.8%	7.3%	3.2%	0.6%	0.1%	0.0%
JCPLC	0.0%	0.0%	3.6%	46.4%	41.0%	5.7%	2.7%	0.5%	0.1%	0.0%
MEC	0.0%	0.2%	3.9%	46.2%	39.9%	6.1%	3.0%	0.6%	0.1%	0.0%
OVEC	0.0%	0.1%	2.0%	46.4%	40.7%	7.0%	3.1%	0.6%	0.1%	0.0%
PECO	0.0%	0.1%	5.6%	46.4%	39.2%	5.5%	2.6%	0.5%	0.1%	0.0%
PE	0.0%	0.1%	2.1%	46.1%	40.2%	7.2%	3.5%	0.5%	0.1%	0.0%
PEPCO	0.0%	0.1%	2.5%	46.3%	38.2%	7.4%	4.4%	1.0%	0.2%	0.0%
PPL	0.0%	0.1%	4.0%	46.2%	40.6%	5.7%	2.7%	0.5%	0.1%	0.0%
PSEG	0.0%	0.0%	3.2%	46.4%	41.2%	5.8%	2.8%	0.6%	0.1%	0.0%
REC	0.0%	0.1%	3.2%	46.1%	40.5%	6.2%	3.0%	0.6%	0.1%	0.0%

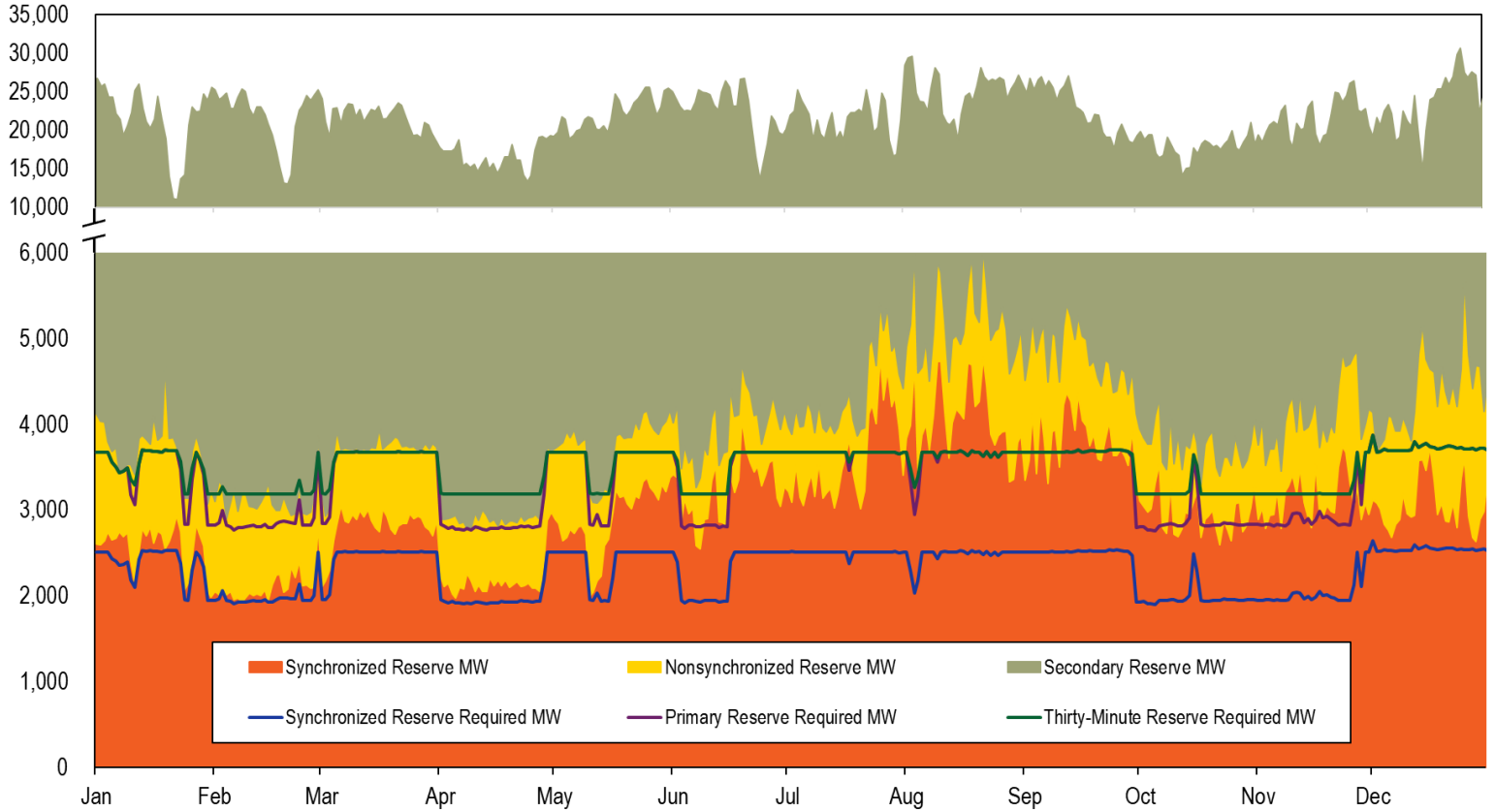
Hourly Average Load and PLMP – DLMP Delta 2025



Monitoring Analytics

RESERVES

Real-Time Average Cleared Reserves and Requirements



Monitoring Analytics

Day-Ahead & Real-Time RTO Average Reserve MW

		Average Synchronized Reserve MW		Average Nonsynchronized Reserve MW		Average Total Primary Reserve MW		Average Secondary Reserve MW		Average Total Thirty-Minute Reserve MW	
Year	Month	DA	RT	DA	RT	DA	RT	DA	RT	DA	RT
2025	Jan	2,637	2,582	1,313	1,130	3,950	3,712	13,079	17,602	17,028	21,313
2025	Feb	2,180	2,111	1,220	1,013	3,400	3,124	13,024	18,628	16,424	21,752
2025	Mar	2,824	2,802	932	881	3,756	3,683	11,763	17,934	15,519	21,617
2025	Apr	2,171	2,183	809	776	2,981	2,959	8,536	13,507	11,517	16,466
2025	May	2,636	2,894	1,021	864	3,657	3,758	11,589	18,348	15,246	22,107
2025	Jun	2,686	3,223	953	734	3,639	3,957	12,801	18,589	16,440	22,546
2025	Jul	3,020	3,581	823	747	3,843	4,327	11,687	16,947	15,529	21,275
2025	Aug	2,903	4,068	1,016	1,096	3,918	5,165	12,462	19,947	16,380	25,112
2025	Sep	2,997	3,815	912	981	3,909	4,795	11,392	18,112	15,301	22,907
2025	Oct	2,319	2,952	627	789	2,946	3,741	9,098	14,211	12,044	17,953
2025	Nov	2,306	3,130	967	971	3,273	4,102	10,796	17,406	14,068	21,507
2025	Dec	2,841	3,066	1,318	1,298	4,159	4,365	11,662	19,031	15,821	23,396

Day-Ahead & Real-Time MAD Average Reserve MW

Year	Month	Average Synchronized Reserve MW		Average Nonsynchronized Reserve MW		Average Total Primary Reserve MW		Average Secondary Reserve MW		Average Total Thirty-Minute Reserve MW	
		DA	RT	DA	RT	DA	RT	DA	RT	DA	RT
2025	Jan	2,004	1,985	985	925	2,989	2,909	NA	NA	NA	NA
2025	Feb	1,968	1,971	890	839	2,858	2,810	NA	NA	NA	NA
2025	Mar	2,034	1,966	657	667	2,690	2,633	NA	NA	NA	NA
2025	Apr	1,838	1,783	524	599	2,362	2,382	NA	NA	NA	NA
2025	May	1,819	1,833	592	619	2,411	2,451	NA	NA	NA	NA
2025	Jun	2,036	2,040	575	613	2,611	2,653	NA	NA	NA	NA
2025	Jul	2,068	2,038	525	621	2,593	2,659	NA	NA	NA	NA
2025	Aug	2,043	2,073	601	738	2,644	2,811	NA	NA	NA	NA
2025	Sep	1,956	2,089	696	771	2,651	2,860	NA	NA	NA	NA
2025	Oct	2,012	1,930	538	691	2,550	2,620	NA	NA	NA	NA
2025	Nov	2,156	1,972	721	714	2,877	2,686	NA	NA	NA	NA
2025	Dec	2,238	2,009	867	863	3,104	2,872	NA	NA	NA	NA

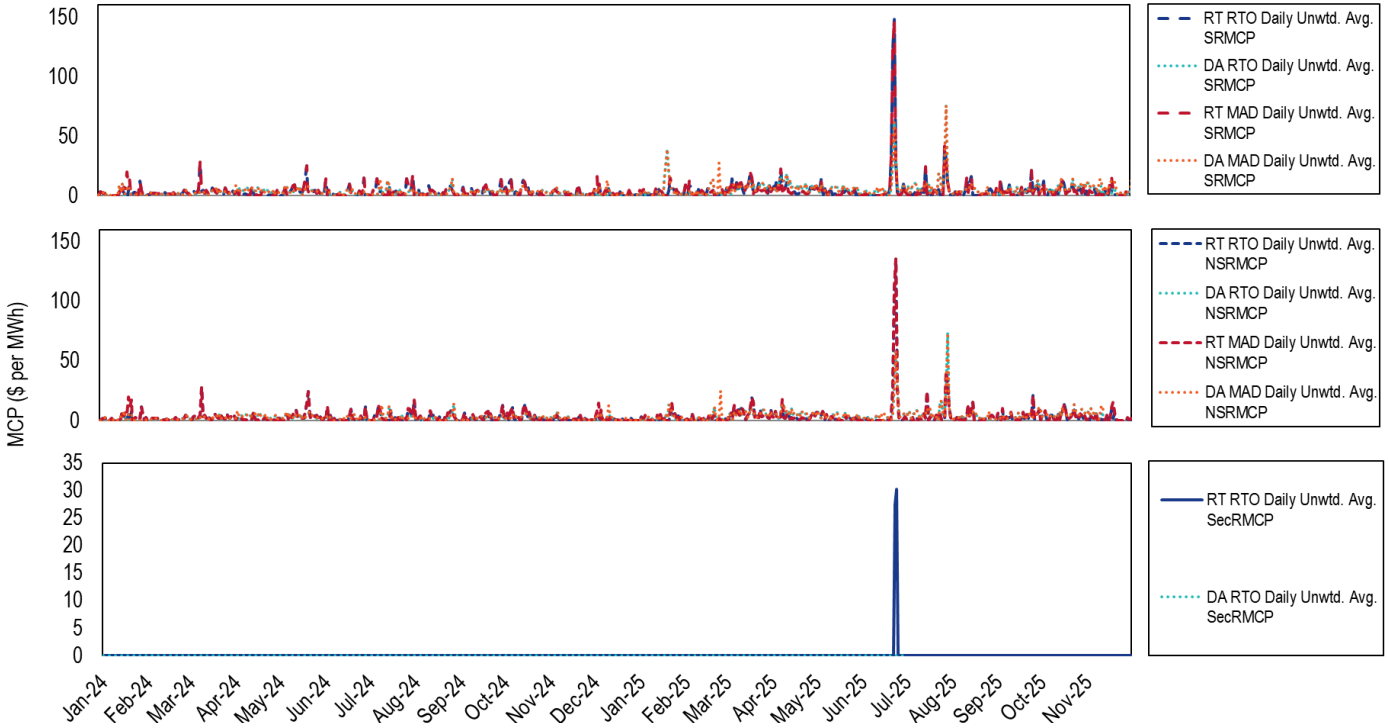
Total Reserve Settlements by Month

Year	Month	Total Day-Ahead Credits			Total Balancing MCP Credits			Total LOC Credits		
		SR	NSR	SecR	SR	NSR	SecR	SR	NSR	SecR
2025	Jan	$9,766,427	$1,310,758	$0	($93,903)	($807,014)	$0	$1,086,575	$185,652	$243,258
2025	Feb	$5,437,781	$698,931	$0	($126,526)	($300,892)	$0	$779,549	$96,940	$133,463
2025	Mar	$15,181,061	$2,079,574	$0	($1,464,818)	($470,698)	$0	$2,047,513	$289,300	$126,843
2025	Apr	$13,256,012	$1,984,502	$0	($345,197)	($247,956)	$0	$1,268,522	$91,497	$135,333
2025	May	$10,685,430	$1,340,915	$0	($13,743)	($151,404)	$0	$786,811	$64,475	$420,010
2025	Jun	$15,012,782	$2,457,199	$0	($4,327,200)	($2,282,555)	($986,243)	$4,657,382	$102,702	$1,825,703
2025	Jul	$22,507,389	$3,413,482	$0	($310,371)	($958,506)	$0	$2,566,238	$121,292	$1,274,869
2025	Aug	$7,390,714	$1,266,236	$0	$20,554	($425,994)	$0	$1,016,144	$67,415	$1,150,153
2025	Sep	$10,131,551	$1,261,458	$0	($840,026)	($283,100)	$0	$1,576,176	$163,072	$850,947
2025	Oct	$11,138,947	$1,708,180	$0	($485,436)	$132,540	$0	$1,527,077	$61,983	$929,807
2025	Nov	$9,137,073	$1,411,665	$0	($11,596)	($124,998)	$0	$1,376,621	$71,961	$691,986
2025	Dec	$9,324,658	$1,658,885	$0	($434,964)	($113,519)	$0	$1,998,439	$184,463	$1,540,616

Year	Month	Total Shortfall Charges			Total Credits		
		SR	NSR	SecR	SR	NSR	SecR
2025	Jan	$0	NA	$0	$10,759,099	$689,396	$243,258
2025	Feb	$118,146	NA	$0	$5,972,657	$494,978	$133,463
2025	Mar	$0	NA	$0	$15,763,757	$1,898,176	$126,843
2025	Apr	$0	NA	$0	$14,179,338	$1,828,043	$135,333
2025	May	$0	NA	$0	$11,458,498	$1,253,986	$420,010
2025	Jun	$0	NA	$0	$15,342,965	$277,346	$839,460
2025	Jul	$76,684	NA	$0	$24,686,572	$2,576,268	$1,274,869
2025	Aug	$0	NA	$0	$8,427,413	$907,657	$1,150,153
2025	Sep	$159,581	NA	$0	$10,708,120	$1,141,430	$850,947
2025	Oct	$114,170	NA	$0	$12,066,418	$1,902,703	$929,807
2025	Nov	$4,280	NA	$0	$10,497,818	$1,358,628	$691,986
2025	Dec	$0	NA	$0	$10,888,133	$1,729,828	$1,540,616

- Only February, July, and September through November had spin events that lasted at least 10 minutes, so only those months had synchronized reserve shortfall charges.
- Total credits were higher in June due to dozens of intervals of shortage pricing.
- Higher day-ahead credits in July correspond with higher prices during hot weather alerts and maximum emergency generation alerts.
- Higher SecR credits in December correlate with cold weather on the 14th and 15th.

Reserve Prices: January 2024 through November 2025



- Many intervals of shortage pricing seen in June 2025 heatwave
- Higher day-ahead prices on July 24, July 25, July 28, and July 29 correspond with maximum emergency generation alerts and hot weather alerts.

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Exhibit: AG-11
Date: February 13, 2026
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An Informa TechTarget Publication

UTILITY DIVE

DIVE BRIEF

PJM capacity prices hit record high as grid operator falls short of reliability target

A 6.6-GW shortfall could trigger a backstop procurement to bolster PJM's reserve margin, according to Jefferies analysts.

Published Dec. 18, 2025



Ethan Howland
Senior Reporter

The PJM Interconnection control room. Capacity prices in the grid operator's latest capacity auction hit a $333.44/MW-day price cap across its region, PJM said on Dec. 17, 2025. Permission granted by PJM Interconnection

Dive Brief:

- Capacity prices in the PJM Interconnection's latest capacity auction hit a $333.44/MW-day price cap across its region, setting a record-high price for the third auction in a row, the grid operator said Wednesday.
- PJM procured 145,777 MW in the auction, about 6,625 MW below the grid operator's 20% installed reserve margin target — an estimate of how much capacity is needed to prevent more than one unexpected power outage every 10 years.
- PJM estimates that without a temporary price cap that was established in an agreement with Pennsylvania Gov. Josh Shapiro, D, the capacity price for the 2027-28 delivery year would have been nearly $530/MW-day, or about 60% higher.

Currently, PJM's next capacity auction, set to be held in July, won't include the price cap — but some industry observers expect a price cap will be reinstated.

Dive Insight:

The auction results were nearly the same as PJM's last auction, which cleared at $329.17/MW-day. As a result, ratepayers will see little change in their electric bills because of the auction, Stu Bresler, executive vice president for market services and strategy at PJM, said during a media briefing.

The cost of the auction climbed to $16.4 billion from $16.1 billion in the previous auction, up 1.9%. Capacity costs make up a relatively small part of electric bills.

PJM capacity costs hit a record high

The cost of PJM's capacity auction in billions of dollars.

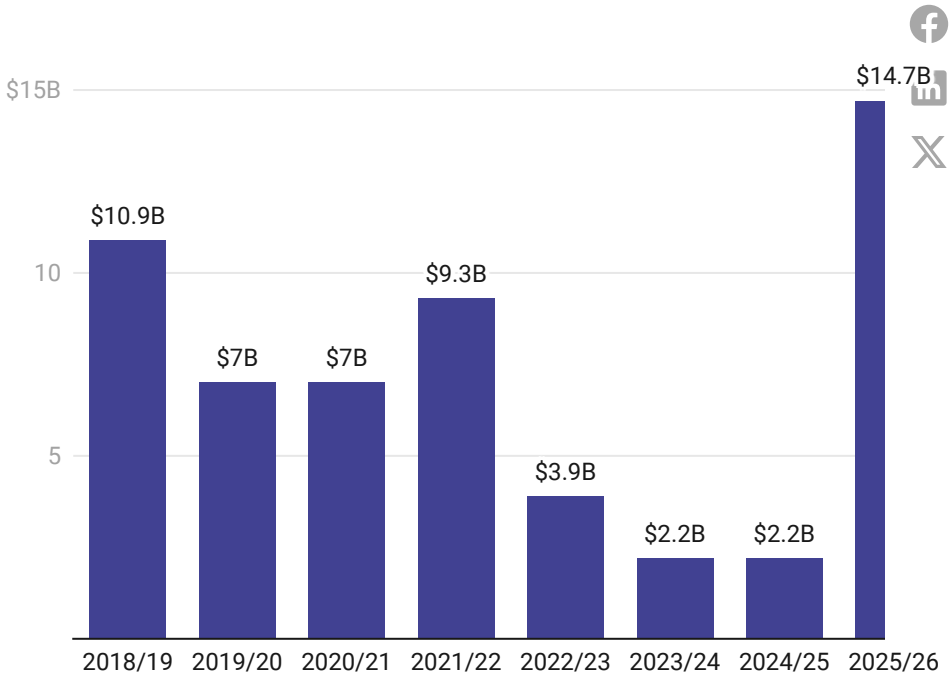


Chart: Ethan Howland/Utility Dive • Source: PJM Interconnection • Get the data • Created with

Gas-fired generation accounted for 43% of the cleared capacity, followed by nuclear at 21%, coal at 20%, demand response at 5%, hydroelectric at 4%, wind at 2%, oil at 2% and solar at 1%, according to PJM.

The auction cleared 774 MW of "unforced capacity" — a measure of a resource's accredited value — of new generation and power plant uprates.

"It's unsurprising that almost no new capacity showed up because projects in PJM are still struggling to get built," Julia Hoos, head of USA East at Aurora Energy Research, said in an email Thursday.

Some of the backlog is caused by permitting challenges, a difficult financing and regulatory environment, and gas turbine shortages, she said.

In part, the latest auction results were driven by a 5,250-MW increase in PJM's demand forecast — almost entirely driven by data centers — and a roughly 370-MW increase in cleared "unforced capacity" compared to the previous auction, Bresler said.

While PJM failed to buy enough capacity to meet its installed reliability margin, there are signs the shortfall will shrink by the time the delivery year begins on June 1, 2027, according to Bresler.

PJM's demand forecast for the auction was based on an estimate released in January. However, PJM is set to release a new load forecast next month that could be significantly lower, partly based on stricter vetting of potential large loads and a reduced economic outlook, Bresler said.

"We expect it to be appreciable, so it will make a meaningful difference leading into the delivery year," he said.

Also, planned power plant retirements may be delayed and wind generation that was unable to participate in the capacity auction will still be delivering electricity in the winter when the PJM system has the most reliability risk, according to Bresler.

PJM could acquire additional capacity if needed in its "incremental auctions" that are held to address supply-demand changes before a capacity year takes effect, Bresler noted.

The auction results don't reflect a wave of recent investment announcements because generating projects take years to build and PJM's auction calendar has been compressed over multiple auction cycles, according to the PJM Power Providers Group and the Electric Power Supply Association.

"Arguments in support of dramatic policy reversals," such as permitting utilities to rate base generation, "would do nothing to speed construction and would further exacerbate concerns about affordability," the trade groups said.

Reliability backstop procurement?

PJM's rules require it to launch an investigation when it fails to meet its reliability reserve target by more than one percentage point, the grid operator said in its auction report. It missed the 20% target by 5.2 percentage points.

That could trigger a procurement process for backstop capacity, according to Jefferies equity analysts.

"We increasingly see an accelerated backstop procurement as the 'default' immediate fix with a FERC filing to request this coming from the board in '26," the analysts said. "If PJM proceeds with this, expect a special RFP process to procure capacity-only resources at potentially elevated costs at term (15-years?)."

The auction results increase pressure on state utility regulators to create new tariff structures to ease concerns about shifting costs from data centers to other utility customers, analysts with research firm Capstone said.

The analysts doubt PJM's board will propose major changes to the grid operator's rules for adding large loads to its system, the analysts said. PJM's board is developing a proposal based on suggestions made during a fast-track stakeholder process that failed to reach a consensus on large loads. The board aims to file a proposal for review by the Federal Energy Regulatory Commission next month, Bresler said.

"Instead, we expect the upcoming filing to focus on high-consensus items that will receive FERC approval and align with Department of Energy … principles concerning expedited interconnection for generators paired with data centers," the Capstone analysts said.

Consumer groups call for reforms

PJM is "mired in bureaucracy" while other regional grid operators are moving faster to bring new power online, according to the Ohio Manufacturers' Association.

"Customers should be paying to bring new generation online, not overpaying the same legacy plants," Ryan Augsburger, OMA president, said in a statement. "If PJM's auctions continue to deliver results like this, the system must be rebuilt from the ground up."

Chicago-based Citizens Utility Board echoed OMA's concerns while calling on PJM to extend the capacity auction's price cap and eliminate the price floor.

"Our capacity market is breaking under the weight of data center demand and a dysfunctional interconnection queue," CUB

Executive Director Sarah Moskowitz said in a statement. “Even worse, since the auction results fell below the reliability requirement, consumers are getting the worst of all worlds: paying more money for reduced electric reliability, while existing generators get a windfall.”

Constellation Energy cleared 17,950 MW in the auction, the power producer said in a U.S. Securities and Exchange filing. As a result, it should garner about $2.2 billion in revenue for the 2027/28 capacity year.

Vistra cleared 10,566 MW and Talen Energy cleared 8,745 MW, they said in SEC filings. That will generate $1.3 billion and $1.1 billion in capacity revenue for the companies.

POLICY BRIEF

Connection Costs

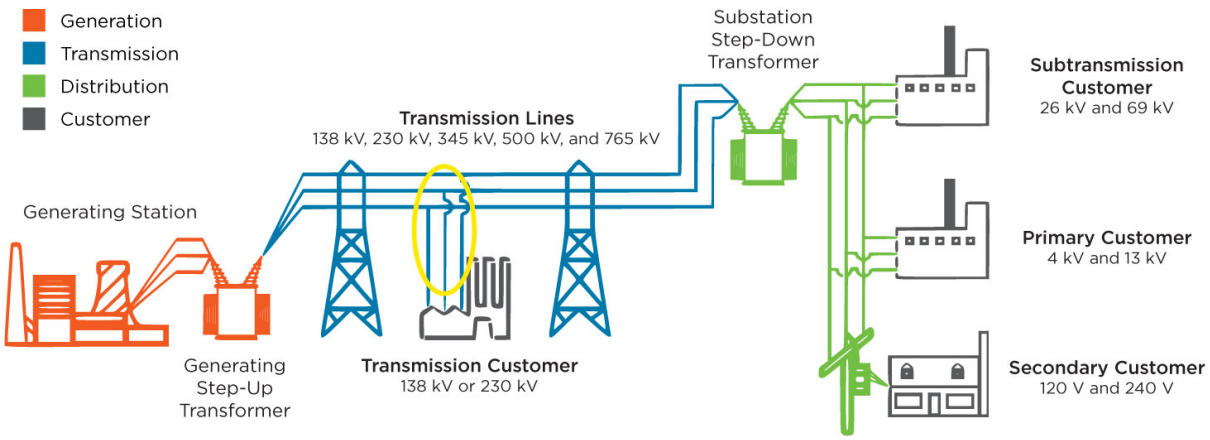
Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid

Introduction

Electricity demand from new data centers is reshaping the utility industry. After two decades of minimal load growth, many utilities are forecasting and preparing for a 30–80 percent increase in electricity sales in 10 years (MISO 2024). In the region served by PJM, the regional transmission organization (RTO) for which this growth has been the greatest thus far, all customers' electric bills are rising to pay for new electricity supply (Monitoring Analytics 2025). Costs are also rising because all customers pay for the new transmission lines required to connect new, large data centers. Such costs are passed on to all customers because existing rules for recovering the costs of transmission upgrades did not anticipate that individual customers could create such high demand and subsequent high costs.

The Union of Concerned Scientists (UCS) found that in 2024 alone, utilities in seven PJM states passed more than $4.3 billion in additional costs on to customers, with billions more still to come. These costs come from local transmission upgrades made to provide transmission-level service directly to data centers. This brief's appendix tracks these costs from the data center driver to their inclusion in regional transmission plan costs.

Figure 1. Utility Transmission Lines



Transmission lines may have direct connections to customers (marked in yellow) and connect to the distribution system. The federal government supervises transmission costs and rates, while state governments largely supervise distribution. Source: NPS 2023.

New Rules Needed for Data Center Boom

Historically, the typical new data center's electricity demand has been under 10 megawatts (MW), and grid connections have been similar to ubiquitous, low-voltage retail service on existing distribution lines. In contrast, utilities usually charge the costs of connecting a new, nonstandard individual customer directly to that customer. Now, the development of 100–400 MW data centers is widespread, and numerous states host projects under development that will call for utilities to deliver 1,000 MW or more.

This leap in demand requires something new: high-voltage transmission infrastructure built to reach new customers, which are, increasingly, data center facilities (Lazar et al. 2020). In PJM's service area, a hotbed of data center activity, states and commonwealths with utilities designing and building connections for 100–1,000 MW load requests include Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia.

Utilities have 100-year-old processes and regulatory mechanisms for supporting both economic growth and load growth with grid expansions. State public utility commissions (PUCs) have established standard regulatory practices for utilities to build new connections, provide service to new customers, and allocate the resulting revenues and costs. However, the data center boom—particularly the extraordinary size of individual new facilities, leading to direct connection to the transmission (high-voltage) system, rather than the distribution (low-voltage) system—is unlike past growth addressed by these existing rules and regulatory assumptions.

The rapid growth in data center electricity demand creates a new category of costs (which are tallied in the appendix) in addition to the costs of maintaining adequate supply. Connecting large data centers to the existing transmission system can raise electricity bills for all customers served by the same utilities. The existing rules and practices allow for this—the worst—outcome, largely because regulatory cost reviews are practically nonexistent for these transmission-level facilities and utility incentives reward this practice.

Grid Costs for Data Centers Fall Through a Regulatory Gap

Transmission-level connections for data centers incur costs under federally regulated rates, which are mixed in with typical transmission costs. These typical costs reflect customers' collective use, reliability needs, and the replacement of aging equipment. The costs are then passed on to retail customers via state PUC-approved rate cases. The process obscures any tracking of cost causation for these new transmission-level data center connection investments.

States supervise the rates and services of each investor-owned electric utility with a retail service territory. These utilities own and expand the network of wires that connect the electric supply to customers, including both low-voltage distribution and high-voltage transmission. However, the federal government has jurisdiction over the review of utility company expenses for transmission investment and expansion. This boundary between state and federal jurisdiction was established under the assumption that transmission lines would be used only for wholesale, not retail, deliveries of energy. This assumption generally supports the notion that customers' collective use drives transmission-level investments and that costs should be allocated broadly across all customers.

Transmission is generally defined as grid infrastructure that operates above 69 kilovolts (kV). However, the distinction between transmission and the lower-voltage electricity distribution

network that reaches individual customers for retail service is determined on a case-by-case basis. One factor in this determination is whether the higher-voltage transmission delivers electricity across state boundaries, thus directly involving interstate commerce (Lazar et al. 2020). Because interstate commerce is involved, the Federal Energy Regulatory Commission (FERC) administers transmission service conditions, rates, and terms, while states regulate the same for distribution service.

Federal supervision of transmission is divided into two categories: local and regional transmission planning (FERC 2007). Federal rules evolved with the creation of independent system operators (ISOs) and RTOs, which make regional transmission plans in much of the US (FERC 2011; FERC 1996). In the current approach, utilities provide local planning to replace and expand transmission primarily serving their own customers. These local plans are funneled through ISO/RTO approval processes and incorporated into the regional plans. Costs for local transmission projects are allocated entirely to the zone in which the transmission facilities are located, typically mirroring the utility's service territory (Monitoring Analytics 2023). Thus, the locally planned transmission is presumed to be for wholesale market purposes. Regardless of whether the utility and state are in an RTO region, utility-planned transmission is added to FERC-supervised rates, which are then paid for by the customers in the utility's service territory.

Billions in Costs Now, Billions More Coming

Consumer representatives and advocates have raised concerns about utilities' local transmission planning because of the limited scope of review, the potential for poor planning efficiency, and the unsupervised costs of the resulting transmission upgrades (Chen and Hartman 2022; Wayner et al. 2024). Increasingly, data centers' connection costs are being allocated to all customers of the same utility (Martin and Peskoe 2025). The high concentration of data centers in states served by PJM has altered the profile of local transmission investment.

From 2022 through 2024, utility companies initiated over 150 local transmission projects in Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. These projects were needed only to connect data centers. The transmission expansions have cost consumers $5 billion thus far (including over $4.3 billion in 2024, as shown in Table 1 and the appendix) and, under existing rules, have been allocated to all customers of these utilities. Early indications for 2025 show that many more new connection costs will follow this same pattern, raising customer bills.

Table 1. Data Center - Caused Transmission Costs in Millions of Dollars Approved in 2024

State	Number of Projects	Cost (Millions)
Illinois	3	$239.0
Maryland	4	$107.5
New Jersey	8	$14.5
Ohio	37	$1,299.7
Pennsylvania	16	$491.8
Virginia	60	$1,988
West Virginia	2	$215.8
Total	130	$4,356.3

PJM's operating agreement requires utilities to disclose their local transmission plans as part of its FERC-approved planning process (PJM Interconnection 2025). Through the PJM Transmission Expansion Advisory Committee (TEAC), utilities submit transmission assumptions and designs for review and comment before adding locally planned facilities to the Regional Transmission Expansion Plan (RTEP). Utilities can bring specific requests for new customer service at a specific location to TEAC's monthly meetings. There, they present initial designs for building transmission lines and substations to fulfill these individual customers' requests for connection.

Utilities briefly describe the customer demand levels and the expected year of need. These briefings are informational only; no PJM approvals are required. Throughout this process, utilities disclose the names of new substations (often to be built at the customer's location), the cost of major project segments, and a tracking number that will appear in PJM's annual RTEP. From that point through state proceedings to determine retail customers' bills, the causation of these costs (attaching a single customer to the transmission system) is not visible.

Current Practices Obscure Money Trail

With the limited reporting of transmission system expenditures needed to connect data center customers to the power grid, the key question must be asked: "From where do the utilities collect that money?"

Utilities are pushing reforms that would ensure data centers pay their bills for 10–15 years (Commonwealth Edison Company 2025; Indianapolis Power & Light Company 2025; Ohio Power Company 2025), yet utilities are not taking steps to prevent these connection costs from being assigned to rates paid by all consumers. Throughout the US, state PUCs assign FERC-approved aggregated transmission costs to retail customers without cost causation information. Cost causation information could be reported to inform state rate-making proceedings through three potential avenues.

1) First, if utilities collected prepayments from data center owners for their connection costs at the outset, this would be reflected in the utilities' TEAC descriptions and RTEP tracking, which is available through PJM. It would also be reflected in the utilities' state filings—which report "customer advances" or "contributions in aid of construction"—or in the utilities' annual transmission rate FERC filings under Account 107, which is titled "Construction Work in Progress" (Appalachian Power Co v. FERC 2025).

2) Alternatively, if utilities maintained categories of customer classes that cause transmission costs, then the FERC-supervised annual RTEP reporting of transmission investments and subsequent transmission revenue requirements would distinguish costs for the direct connection of customers from other investments included in these reports.

3) If, in their state PUC filings, utilities used a category of transmission costs for the direct connection of customers or added a new, very large customer class to their recordkeeping and rate collections, subsequent reviews of costs to serve customers in state rate proceedings would separate the transmission costs caused by that one large customer, or a new class of very large customers, from the costs charged to other customers.

These changes would allow utilities and/or states, at rate-making proceedings, to assign transmission connection costs to the customers that cause the costs. However, utilities usually assign transmission costs for data center connections to all of their customers. With this practice, costs caused by a single customer are not differentiated or separated when annual local transmission plans are processed and rates are calculated. This is not the application of cost causation that is so often cited in utility cost allocation debates (Bonbright 1961).

UCS examined these three reporting approaches to determine whether utilities in the PJM territory use them to report and collect transmission costs to connect large customers.

1) Do utilities collect transmission connection costs from data centers, either up front or by direct assignment?

Yes, but only in 5 percent of cases. In 2024, utilities described six of the 130 transmission connection projects for large loads as having no cost to other customers and being paid for by the single customer.

Consequently, utilities assigned $4.3 billion in connection costs for the remaining 95 percent of data center projects to the same pool of costs paid by all consumers. Prepayment from customers for direct connections to the transmission system would lower utilities' rate base and profits (Lazar et al. 2020).

If any of the other 124 projects are counted as having customer contributions, either through special contracts or line extension policies, that revenue has not been credited in the development of costs collected through transmission rates.

2) Do utilities maintain categories of customers with transmission connection costs so that these costs can be assigned separately?

No, because utilities' representation of costs through FERC-supervised RTEP reports and revenue requirements does not distinguish a category of retail customers. This makes it impossible to allocate costs to the largest customers. An existing loophole allows the cost of connecting new data centers to transmission lines to raise the rates of all consumers (Martin and Peskoe 2025).

3) ***Do utilities keep transmission connection costs separate from other transmission costs?***

No, except when state legislation has introduced such a requirement (Next Generation Energy Act 2025). Utility rate filings with transmission costs set by FERC formula rates are provided to state regulators, but do not distinguish or separate data center connection costs from other transmission costs spread across all utilities' customers.

Protecting Customers

To protect customers from unfair cost burdens, retail rate cases usually include an important step: a cost-of-service study. This study determines which costs should be included in which customers' rates (Lazar et al. 2020) The lack of information about which large customers are causing transmission costs, however, prevents the rate-setting process from working well. Enforcing the principle of cost causation and assigning costs to a class of very large customers (i.e., users that connect at the transmission level) require the regulatory process to include the tracking of new patterns of single customers causing specific transmission upgrades that would not be needed but for the new customer.

In a state utility commission rate case, regulators set rates for customer classes to reflect the different costs of serving groups of customers and the revenues from those customers (Lazar et al. 2020). Responding to a recent formal inquiry, one Pennsylvania utility explained that revenues from data centers are allocated only to lowering rates of the largest customer class and do not benefit all customers (Duquesne Light 2025). Hence, revenues are recognized only for the largest customer class, but not the costs. This is standard in all US utility rate-making.

Recommendations

Fair and prudent allocation of power sector infrastructure costs requires care. Utilities must track costs from these interconnection/line extensions to the appropriate retail rate class, and state and federal regulators must oversee this process. State and federal regulators must require that costs be assigned to the specific customer—or an appropriate rate class that is causing the costs—to avoid subsidization by all other customers. Simply creating a rate class for the largest new customers will not solve this problem unless the costs presently mixed with other transmission costs are separated.

When creating retail rates for large customers, regulators must allocate the costs of transmission-level connections to the customer or class responsible for those costs. Doing so requires tracking the costs of that type of connection and the retail customers that are causing the costs. To that end, UCS recommends the following:

1) FERC should require transmission built for single customers to be paid for by those customers, as is the requirement for new generators.

2) FERC and state PUCs should require utilities to track transmission costs caused by specific customers through the rate-setting processes.

3) FERC should require utilities to create a customer class in FERC formula rates for customers with direct transmission connection costs.

4) State PUCs should require utilities to recognize the transmission costs created by direct connection customers in retail rate cost-of-service studies.

Without one or more of these additional requirements, action by the utility, PUC, or state legislature to create a new customer class for very large consumers to be used in retail rate-making will not capture transmission costs or new generation costs.

UCS took these recommended steps to create the tables in the appendix. The tables include links to information on collecting and tracking transmission connection costs for data centers in Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia.

As utilities prepare their 2025 transmission plans to build additional transmission lines for connecting data centers, the same PJM websites will provide similar information for subsequent years' expenditures.

Author

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THE NEW REALITY OF POWER GENERATION

An Analysis of Increasing Gas Turbine Costs in the U.S.

SEPTEMBER 2025

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Mr. Phil Besuner has over 40 years' experience analyzing and evaluating statistical safety, risk, reliability, and related engineering issues.

The capital costs for new gas combustion turbine (CT) and combined cycle gas turbine (CCGT) power plants in the United States have increased significantly in recent years.

While anecdotes of these higher costs are becoming more common, the specific data is often difficult to access. Much of the most current and detailed market information on gas turbine costs is contained within Integrated Resource Plans (IRPs) and Certificates of Public Convenience and Necessity (CPCNs), which are often confidential. Furthermore, widely available public datasets, such as the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) or the Energy Information Administration's (EIA) Annual Energy Outlook (AEO), are often not up to date with the most current market information and therefore present an underestimated view of project costs.

With these challenges in mind, this white paper, in collaboration with GridLab experts Energy Futures Group and Halcyon, have worked to mine and make available market data from IRP and CPCN filings, providing a clearer and more accurate picture for stakeholders. Halcyon provided data from its platform, which was reviewed and analyzed by EFG. Mr. Philip Besuner, also a GridLab expert, executed several regression analyses to evaluate trends from this data.

While a number of market forces have contributed to this trend, a deeper analysis reveals that these elevated costs are likely to persist rather than decline, at least in the short-midterm. An examination of the most recent financial reports from major gas turbine original equipment manufacturers (OEMs) further supports this conclusion. Key players like GE Vernova, Siemens Energy, and Mitsubishi Power are reporting strong demand and robust order backlogs.

The surge in demand has resulted in significantly extended timelines for bringing new projects into service. Consequently, new combined cycle resources often cannot be brought online until at least **2030–2031**.[1]

These OEMs are capitalizing on global demand driven by increasing electricity consumption, the transition from coal, and the need for flexible power to support renewable energy. This collective positive performance and strategic direction from the OEMs suggest that a significant reduction in gas turbine equipment costs is not anticipated in the near term.[2]

The increasing supply scarcity has translated into greater pricing power for the OEMs, with the three OEMs requiring a reservation fee to secure a manufacturing slot.

For example, Kentucky Utilities and Louisville Gas & Electric (KU/LG&E) acknowledged in their recent CPCN filing that the Companies needed to **pay a $25 million reservation fee** to GE Vernova to reserve a turbine that will be delivered in time for the facility to reach commercial operation in 2030.[3]

It is important to note that the gas turbine market has historically been cyclical, with prices sometimes falling due to factors such as manufacturing over-capacity and heightened competition, as seen in previous years. As recently as 2022, gas turbine prices were expected to drop by 5-10%. A report by S&P Global Commodity Insights noted that while the OEMs are cautiously avoiding the oversupply issues of the early 2000s, they are strategically pursuing growth by focusing on high-margin services and targeted investments like brownfield expansions. They recognize that expansion is constrained by bottlenecks beyond their control, such as in engineering, procurement, and construction (EPC) services, which also contribute to extended project timelines.

1 See for example: KU/LG&E 2024 IRP Volume III, Technology Update, at 4 and 6. Kentucky PSC Case No. 2024-00326.; Duke Energy Indiana 2024 IRP, Table 3-9, at 85-86.; Indiana Michigan Power Company IRP Stakeholder Workshop. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/IN_Stakeholder_Meeting_2.pdf; Santee Cooper 2024 IRP Annual Update, Table 13 at 43.

2 GE Vernova Inc., "First Quarter 2025 Financial Results," press release, April 23, 2025, https://www.gevernova.com/news/press-releases/ge-vernova-reports-first-quarter-2025-financial-results; Siemens Energy AG, "Q1 FY2025 Earnings Release," press release, February 12, 2025, https://www.siemens-energy.com/global/en/home/press-releases/earnings-release-q1-fy-2025.html; Mitsubishi Heavy Industries, Ltd., "FY2024 Financial Results," press release, May 9, 2025, https://www.mhi.com/news/25050901.html

3 Direct Testimony of Lonnie E. Bellar, at 11. Kentucky PSC Case No. 2025-00045.

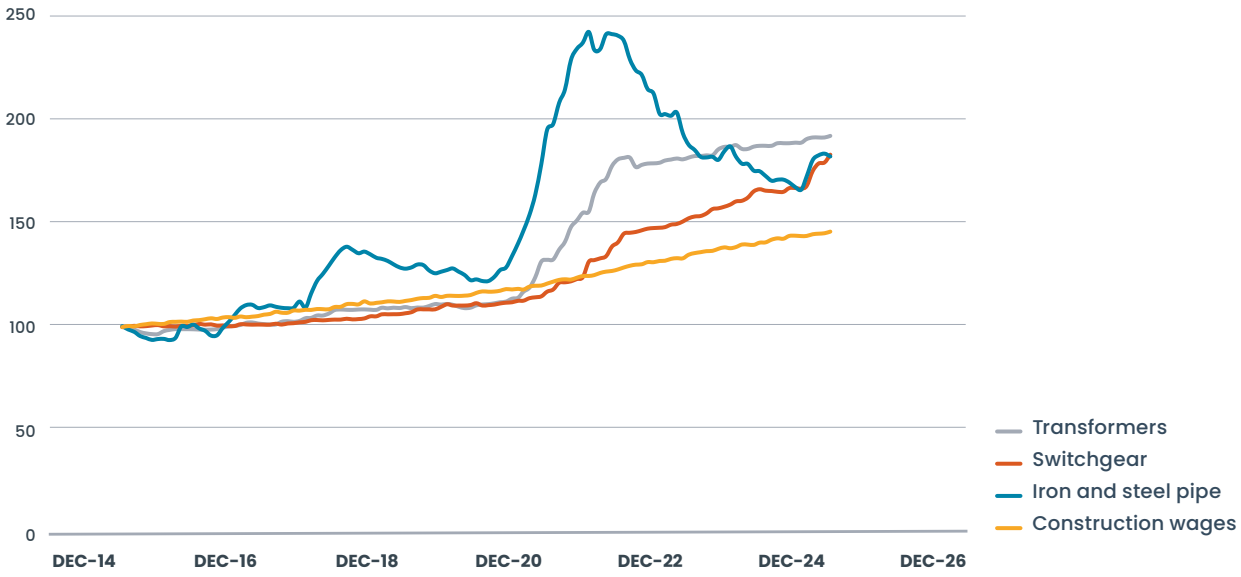
Escalating Costs of Gas Plants

Gas-fired power plants are becoming more expensive to build, and it's not just because of turbine costs, nearly all the key components are seeing price increases that are making these projects much less economically attractive (see figure below).

Transformers have experienced significant price surges due to soaring prices for raw materials such as grain-oriented electrical steel (GOES) and copper. Shortage of GOES is not new. Similarly, switchgear components have seen significant price increases as noted in the Producer Price Index[4]. Natural gas pipeline costs have ballooned in recent years due to the rising cost of steel pipes, which more than doubled between 2020 and 2021.

Along with component prices, labor costs are also increasing. Construction costs have risen due to several factors, including labor shortages, prevailing wages and inflationary pressures. A shortage of skilled workers continues to trouble the industry.

FIGURE 1. Price Index for Non-Turbine Gas Project Components



As of May 28, 2025. Source: S&P Global Commodity Insights; US Bureau of Labor Statistics. © 2025 S&P Global

4 U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Switchgear and Switchboard Apparatus Manufacturing [PCU335313335313], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/PCU335313335313, August 29, 2025

Key Findings on Capital Expenditure for Simple and Combined Cycle Plants

Drawing on the data provided by Halcyon, and a review by EFG and Mr. Besuner, this section presents a detailed analysis of the capital expenditure (CAPEX) trends for new gas turbine power plants. Unlike publicly available datasets, this information provides a granular and up-to-date view of project costs, reflecting the actual market conditions faced by developers.

This paper reveals a significant and persistent increase in the capital costs of new gas combustion turbine and combined cycle gas turbine power plants in the United States. This trend marks a ***stark departure from historical cost assumptions and public cost projections***.

- **Significant Increase in Capital Costs:** Capital costs for new gas CT and CCGT power plants have risen considerably. While projects for completion in 2026 and 2027 were reported at $1,116/kW to $1,427/kW, **recent CCGT projects are routinely reporting costs of $2,000/kW or more**.
- **Costs are Expected to Persist or Increase:** These elevated costs are likely to persist rather than decline, at least in the short-to-midterm. A linear regression analysis of the data indicates that costs increase with the in-service date at a statistically significant rate.
- **Underestimated Public Datasets:** Widely available public datasets underestimate current market costs because they are often not up to date with the most current market information. This creates a significant disconnect between conventional cost assumptions and today's market realities.
- **Market Forces Driving Costs Up:** A combination of factors is contributing to these escalating costs, including:
  - **Demand and Order Backlogs** for the OEMs;
  - **OEM Pricing Power and Reservation Fees:** Increasing supply scarcity has granted greater pricing power to OEMs, who may now require a reservation fee to secure a manufacturing slot.
  - **Rising Costs of Other Components:** Beyond turbine costs, nearly all key components of gas-fired power plants are experiencing price increases.
- **Regional Cost Variations:** The analysis of available data also indicates the existence of regional cost variations, though the specific causes of these differences were not evaluated.

Figure 2 illustrates this trend by showing the reported capital cost ($/kW) for combined cycle gas turbine projects between **2026** and **2031**. Projects scheduled for completion in **2026** and **2027** were reported at a cost range of **$1,116/kW** to **$1,427/kW**, a range that is now significantly outpaced by recent CCGT projects, which are routinely reporting costs of **$2,000/kW** or more. This upward trajectory is further highlighted by the fact that the **2024** NREL ATB projected a **2030** cost of only **$1,638/kW** for a **1x1** combined cycle plant under its moderate scenario. This notable divergence between historical and projected figures and current market costs underscores the disconnect between conventional cost assumptions and today's market realities.[5]

In producing its Annual Energy Outlook, the EIA relies on a Sargent & Lundy report with a 1x1 CC capital cost at $921/kW in 2023 dollars, or $1,058/kW in 2030 if a 2% escalation rate is assumed.[6]

Our capital cost dataset included combined cycle projects with in-service dates between 2026 and 2031 and combustion turbine projects with in-service dates between 2025 and 2029 (see tables in Appendix). We assumed these costs (except for one observation)[7] were all escalated to their in-service year and then fit a linear regression line to each of the two datasets based on operating year. Not surprisingly, costs go up with in-service date at a statistically significant rate[8], which is aligned with broad industry expectations.

Figure 3 shows the simple cycle GT cost data analyzed. The content of Figure 4 directly addresses the operating year differences of both CC and simple cycle GT costs.

Our analysis of the available data, despite its limited size, indicates the existence of regional cost variations. The causes of these differences were not evaluated but are statistically apparent in the dataset and is presented in Figure 5.

5 NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/. The NREL ATB is reported in 2022 dollars. The 2030 overnight capital cost was converted into nominal dollars by assuming a 2% inflation rate on the $1,398/kw reported 2030 cost in the NREL ATB.

6 Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies (January 2024). Table 1.2 at III. Retrieved from https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf. The report shows a 2023 cost of $921/kW. Applying a 2% inflation rate results in the 2030 cost.

7 One unit had a reported 2024 cost that was not yet escalated and we used a Handy-Whitman-based 4.7% rate to escalate that cost to its 2030 in-service year.

8 We used more complex regression models to look at the effects of manufacturer, mW capacity, and other dataset variables. All such effects fell well short of statistical significance.

FIGURE 2. CCGT Capital Cost ($/kW) with Linear Regression Fitted to Data

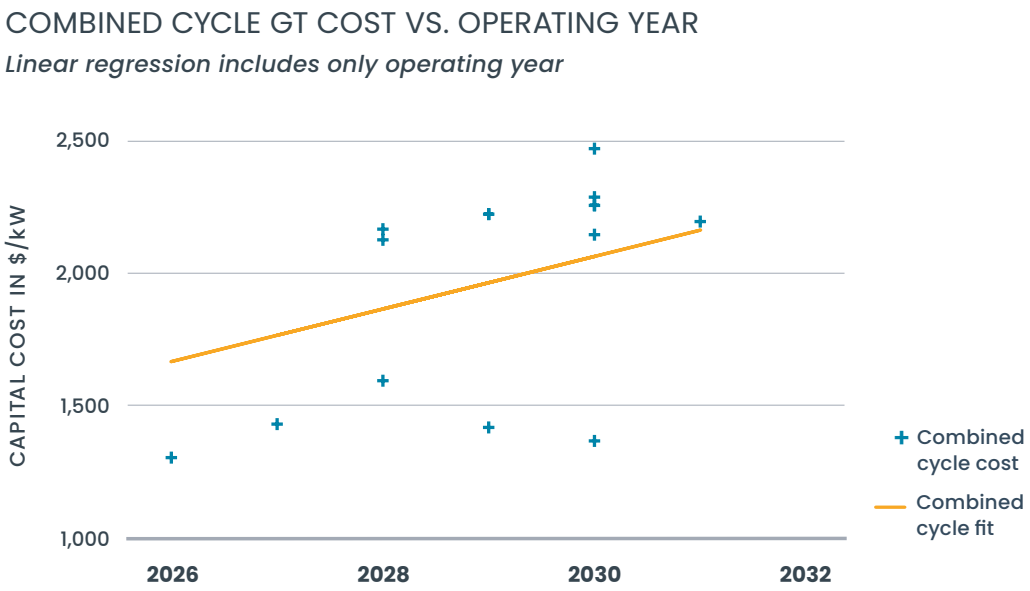


FIGURE 3. CT Capital Cost ($/kW) with Linear Regression Fitted to Data

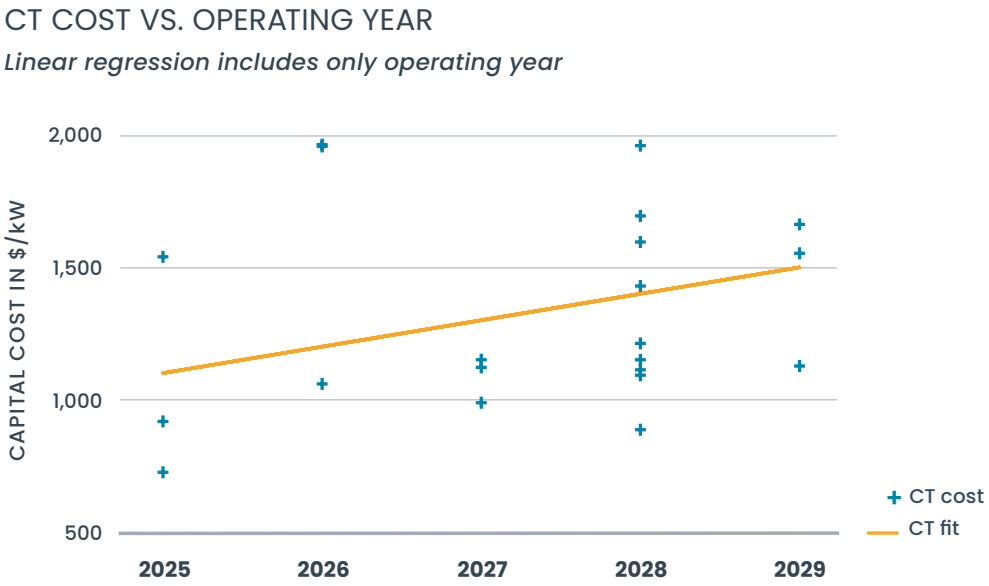


FIGURE 4. Yearly Comparison of Capital Costs

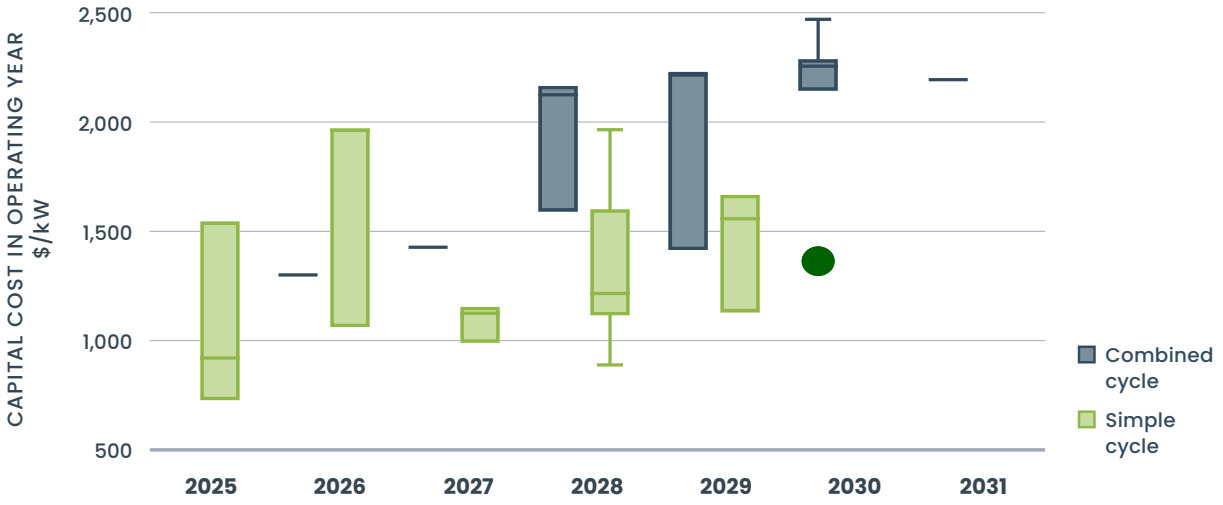


FIGURE 5. Regional Differences in Capital Cost



Implications

The sustained increase in gas turbine costs and project timelines has significant implications for energy planning, policy, and long-term grid reliability. For utilities and regulators, the outdated cost assumptions from public datasets can lead to flawed resource planning and underestimation of project budgets. The extended timelines for turbine delivery create a significant challenge for meeting future electricity demand, particularly as coal and other older fossil fuel plants are retired. The need for substantial reservation fees also affects project financing and risk.

Based on these findings, we offer the following recommendations for stakeholders:

- **Update Cost Assumptions:** Regulators and planners should re-evaluate and update their cost assumptions for gas turbine projects to reflect current market realities. This paper provides a starting point for this effort, offering a new dataset that more accurately reflects contemporary costs.
- **Prioritize Data Transparency:** Regulators should not only facilitate greater access to non-proprietary data from IRP and CPCN filings to improve market transparency, but they should also demand a higher level of contractual certainty in project cost submissions. Regulators should also require a higher level of contractual certainty in project cost submissions, mandating that major components such as EPC services are fully contracted at the time of the CPCN application.
- **Foster Collaborative Planning:** Utilities and regulatory bodies should establish formal, collaborative forums to share real-time market data, including supply chain constraints and cost information, which could inform more realistic and transparent resource planning decisions.
- **Evaluate Flexible Alternatives:** Given the rising costs and delays, a more thorough analysis of a wider array of renewable energy and storage technologies, including utility-scale solar, wind, and battery storage, is crucial to ensuring a robust and cost-effective energy transition.

The data presented in this white paper demonstrates a clear and persistent upward trend in the capital costs of new gas turbine projects in the United States. This is a significant departure from historical trends and public cost projections.

The consequences of these trends are already being felt in the form of extended project timelines, a growing reliance on reservation fees to secure equipment, and a significant disconnect between planning assumptions and on the ground realities. Therefore, it is essential for all energy stakeholders — from regulators to utilities and developers to proactively address these challenges by updating cost assumptions in planning models and rigorously evaluating all available generation and storage options.

Appendix

The two tables in this appendix are a subset of the representative data utilized in the analysis. Additional data can be requested from Halcyon.

TABLE 1. Simple Cycle Combustion Turbine Data [Limited Dataset]

PLANT / UNIT NAME	DATE OF ANNOUNCEMENT	PLANNED / OPERATING YEAR	EIA PLANT ID	EIA ENTITY NAME	STATE	COST PER KW	CAPACITY (MW)	CAPEX ($M)	TECH. TYPE	POWER MARKET	ACTUAL VS. ESTIMATED COST
A.B. Brown	6/28/2022	2025	6137	Southern Indiana Gas & Elec Co	IN	$728	460	$334.8	Simple-Cycle Gas Turbine	MISO	Actual
Aberdeen CT	1/1/2024	2026	3338	NorthWestern Energy - (SD)	SD	$1,969	1,260	-	Simple-Cycle Gas Turbine	SWPP	-
Apache Generating Station GT5 and GT6	10/1/2024	2025	160	Arizona Electric Pwr Coop Inc	AZ	$920	84	$77.3	Simple-Cycle Gas Turbine	WALC	Actual
Castle Bluff Energy Center	6/7/2024	2027	67576	Union Electric Co - (MO)	MO	$1,125	800	$900.0	Simple-Cycle Gas Turbine	MISO	Estimate
Chesterfield Energy Reliability Center	3/3/2025	2029	3797	Virginia Electric & Power Co	VA	$1,557	944	$1,470.0	Simple-Cycle Gas Turbine	PJM	Estimate
Horseshoe Lake	5/31/2023	2029	2951	Oklahoma Gas & Electric Co	OK	$1,130	448	$506.4	Simple-Cycle Gas Turbine	SWPP	Actual
Lone Star Power Station	6/4/2024	2028	-	Entergy Texas Inc.	TX	$1,699	453	$769.6	Simple-Cycle Gas Turbine	ERCOT	Estimate
North Valmy New Peakers	5/31/2024	2028	8224	Sierra Pacific Power Co	NV	$1,433	400	$573.3	Simple-Cycle Gas Turbine	NEVP	Estimated
Parr Replacement Units (GT5 and GT6)	3/10/2021	2025	3291	Dominion Energy South Carolina, Inc	SC	$1,544	114	$176.0	Simple-Cycle Gas Turbine	SCEG	Estimate
Urquhart Replacement Unit (CT #7)	3/10/2021	2028	3295	Dominion Energy South Carolina, Inc	SC	$1,965	200	$393.0	Simple-Cycle Gas Turbine	SCEG	Estimate

TABLE 2. Combined Cycle Combustion Turbine Data [Limited Dataset]

PLANT / UNIT NAME	DATE OF ANNOUNCEMENT	PLANNED / OPERATING YEAR	EIA PLANT ID	EIA ENTITY NAME	STATE	COST PER KW	CAPACITY (MW)	CAPEX ($M)	TECH. TYPE	POWER MARKET	ACTUAL VS. ESTIMATED COST
Brown 12	2/28/2025	2030	1355	Kentucky Utilities Co	KY	$2,144	645	$1,383.0	Combined-Cycle Gas Turbine	PJM	Estimate
Cayuga CC Project	2/13/2025	2029 and 2030	1001	Duke Energy Indiana, LLC	IN	$2,256	1,476	$3,330.0	Combined-Cycle Gas Turbine	MISO	Estimate
Cooper CCGT	11/21/2024	2030	1384	East Kentucky Power Coop, Inc	KY	$1,768	745	$1,317.0	Combined-Cycle Gas Turbine	PJM	Estimate
Homer City Generating Station	4/2/2025	2028/2029	3122	Homer City Generation, L.P.	PA	$2,222	4,500	$10,000.0	Combined-Cycle Gas Turbine	PJM	Estimate
Legend Power Station	6/4/2024	2028	68053	Entergy Texas Inc.	TX	$2,125	754	$1,602.0	Combined-Cycle Gas Turbine	ERCOT	Estimate
McNew Generating Station	9/3/2024	2030	68295	Evergy Kansas Central, Inc	KS	$2,255	710	$1,601.0	Combined-Cycle Gas Turbine	SWPP	-
Mill Creek 5	1/6/2023	2027	1364	Louisville Gas & Electric Co	KY	$1,427	640	$913.4	Combined-Cycle Gas Turbine	LGEE	Actual
Mill Creek 6	2/28/2025	2031	1364	Louisville Gas & Electric Co	KY	$2,194	645	$1,415.0	Combined-Cycle Gas Turbine	LGEE	Estimate
Muscatine Combined Heat and Power Project	9/11/2024	2028	1167	Board of Water Electric & Communications	IA	$2,165	45	$97.4	Combined-Cycle Gas Turbine	MISO	Estimate
Orange County Advanced Power Station (OCAPS)	9/16/2021	2026	66621	Entergy Texas Inc.	TX	$1,300	1,215	$1,580.0	Combined-Cycle Gas Turbine	MISO	Estimate

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The undersigned certifies that a copy of the ***Attorney General's Testimony and Exhibits of Ben Havumaki*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 13th day of February 2026.

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