STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of INDIANA MICHIGAN POWER COMPANY for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2024.	)))))	**Case No. U-21428**

Direct Testimony of Devi Glick

On Behalf of Attorney General Dana Nessel, Citizens Utility Board of Michigan, and Sierra Club

October 17, 2025

TABLE OF CONTENTS

LIST OF EXHIBITS

AG-1:	Resume of Devi Glick
AG-2:	OVEC, 2024 Annual Report
AG-3:	I&M Response to AGSCCUB Request 1-12
AG-4:	2024 State of the Market Report for PJM
AG-5:	Benchmark Cost for ICPA
AG-6:	Gross Avoidable Costs for Existing Generation
AG-7:	Brattle PJM CONE 2026/2027 Study
AG-8:	Unit Power Agreement
AG-9:	Excerpt of FERC application (UPA, ER19-717-000)
AG-10:	I&M Response to AG Request 2-29, U-20530
AG-11:	I&M Response to AGSCCUB Request 1-22

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony in over 65 different proceedings before state utility regulators in more than 20 states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as widely used optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 13 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit AG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Dana Nessel, Attorney General of Michigan, Citizens Utility Board of Michigan, and Sierra Club.

Q Have you testified previously before the Michigan Public Service Commission ("Commission")?

A Yes, I submitted testimony in Case No. U-20224, Indiana Michigan Power Company's ("I&M" or "Company") 2019 power supply and cost recovery ("PSCR") reconciliation docket; Case No. U-20804, I&M's 2021 PSCR Plan docket; Case No. U-20530, I&M's 2020 PSCR reconciliation docket; Case No. U-21052, I&M's 2022 PSCR Plan docket; Case No. U-21261, I&M's 2023 PSCR Plan docket; Case No. U-20805, I&M's 2021 reconciliation docket; Case No. U-

21427, I&M's 2024 PSCR Plan docket; Case No. U-21262, I&M's 2023 reconciliation docket; and Case No. U-21596, I&M's 2025 PSCR Plan docket.

Q What is the purpose of your testimony in this proceeding?

A In my testimony for this proceeding, I evaluate three subjects: First, I evaluate the Company's request to recover costs paid for power from the Ohio Valley Electric Corporation ("OVEC") in 2024. Second, I evaluate I&M's request to recover costs paid to AEP Generation ("AEG") in 2024 for power generated by AEG's portion of Rockport Unit 1. Third, I review the fuel and power purchase costs for I&M's owned share of Rockport Unit 1 that it plans to pass on to customers for 2024.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I discuss how I&M customers paid unreasonable prices, significantly above market, to OVEC for power under the Inter-Company Power Agreement ("ICPA") in 2024. I present several different metrics that can be used to value the services provided under the ICPA. I also outline my recommendations to the Commission to disallow recovery of ICPA costs above market value.

In Section 4, I discuss how I&M customers paid unreasonable prices in 2024, far above market, for the portion of Rockport Unit 1's power that I&M purchased from AEG through a power purchase agreement ("PPA") called the Unit Power Agreement ("UPA"). I explain how these costs are also representative of the costs that I&M passes through to ratepayers for the portion of Rockport Unit 1 that it owns. I explain how the Commission, in I&M's PSCR plan case for 2018, directed the Company to take actions to address the costs of the AEG contract, but

I&M failed to take any such actions. I also outline my recommendations to the Commission to disallow recovery of UPA costs above market value.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of I&M witnesses associated with this proceeding, as well as discovery from other proceedings where applicable. I also rely on public information associated with prior I&M proceedings. To a limited extent, I also rely on certain external, publicly available documents such as State of the Market reports for PJM.

2. Findings and Recommendations

Q Please summarize your findings.

A Table 1 shows OVEC and Rockport revenues and charges in support of my primary findings. My primary findings are:

1. I&M has been purchasing power from OVEC, an affiliate company, at above-market value and passing those costs on to customers. Over the course of 2024, the ICPA cost I&M customers $37.9 million more than the cost of equivalent energy and capacity purchased from the market, and $14.2 million more than the cost of available benchmarks.
2. I&M paid its affiliate AEG for power from AEG's share of Rockport Unit 1 at a cost that was far in excess of market value. Over the course of 2024, the UPA cost I&M customers $64.0 million more than the cost of equivalent energy and capacity purchased from the market, and $30.2 million more than the cost of other available benchmarks.

3. In 2024, the OVEC plants lost money on an energy basis, with I&M's share of energy market losses amounting to $4.5 million. Rockport Unit 1 essentially broke even, earning marginal energy revenues of $0.15 million. This means that OVEC is not passing the lowest bar of economic operations in covering its fuel and variable operating costs with its energy market revenues while Rockport is only barely breaking even. This also means that ratepayers would have been better off in 2024 if the OVEC plants had not operated—even taking into account that I&M would have to pay the demand charges regardless.

Table 1. OVEC and Rockport revenues and charges for 2024 ($2024)

	Cost / revenue category	ICPA (OVEC)		UPA (AEG portion of Rockport 1)	
		I&M share ($Million)	Michigan share ($Million)	I&M share ($Million)	Michigan share ($Million)
A	Energy revenue	$ 24.8	$ 3.5	$ 53.1	$ 7.6
B	Capacity revenue	$ 1.9	$ 0.3	$ 7.5	$ 1.1
C	Ancillary Service Value			$ 1.1	$ 0.2
D	**Total Value (A+B+C)**	**$ 26.7**	**$ 3.8**	**$ 61.7**	**$ 8.8**
E	Energy charge	$ 29.3	$ 4.2	$ 52.9	$ 7.5
F	Demand charge	$ 35.2	$ 5.0	$ 72.8	$ 10.4
G	Taxes	$ 1.4	$ 0.2	$ 3.3	$ 0.5
H	**Total cost (E+F)**	**$ 64.5**	**$ 9.2**	**$ 125.7**	$ 17.9
I	Total cost net of taxes (G-H)	$ 63.1	$ 9.0	$ 122.4	$ 17.5
J	**Energy losses (A-E)**	**$ (4.5)**	**$ (0.6)**	**$ 0.15**	**$ 0.02**
K	**Total losses (D-H)**	**$ (37.9)**	**$ (5.4)**	**$ (64.0)**	**$ (9.1)**
L	**Excess cost based on weighted average benchmark**	**$ (14.2)**	**$ (2.0)**	**$ (30.2)**	**$ (4.3)**

Q Please summarize your recommendations.

A Based on my findings, I offer the following chief recommendations:

1. The Commission should disallow in this proceeding $5.4 million, which is Michigan's jurisdictional share of the total $37.9 million in excess

compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services). This represents the difference between what I&M charged customers for OVEC power, and the equivalent price that I&M would pay to procure the energy and capacity from the PJM market in 2024.

2. Alternatively, based on a weighted average of benchmarks from the Campbell Unit 2 and Belle River PPAs, with taxes removed, the Commission should disallow $2.0 million in excess costs. This represents the Michigan jurisdictional share of the total $14.2 million in excess compensation that I&M paid for OVEC service under the ICPA.

3. The Commission should disallow in this proceeding $9.1 million, which is Michigan's jurisdictional share of the total $64.0 million in excess compensation that I&M paid AEG for power from Rockport under the UPA (relative to the market value of energy and capacity in 2024).

4. Alternatively, based on a weighted average of benchmarks from the Campbell Unit 2 and Belle River PPAs, with taxes removed, the Commission should disallow $4.3 million in excess costs. This represents the Michigan jurisdictional share of the total $30.2 million in excess compensation that I&M paid AEG for power from Rockport under the UPA.

3. I&M Customers Are Paying Unreasonable Prices to OVEC for Power Under the ICPA

i. I&M purchases power from OVEC under the ICPA

Q What is OVEC and how is it related to I&M ratepayers?

A OVEC is jointly owned by 12 utilities in Ohio, Indiana, Michigan, Kentucky, West Virginia, and Virginia. OVEC operates two 1950s-era coal-fired power plants— (1) Kyger Creek, a five-unit, 1,086 MW plant in Gallia County, Ohio, and (2) Clifty Creek, a six-unit, 1,303 MW plant, in Jefferson County, Indiana.

OVEC supplies the power from these plants to the utilities through a long-term contract called the Inter-Company Power Agreement.[1] Together, the utilities are responsible for the fixed and variable costs of OVEC. In turn, OVEC bills the utilities variable, demand, and transmission charges. The Michigan Public Service Commission has found that OVEC is an affiliate of I&M.[2]

Q How often were the OVEC plants operated in 2024?

A The OVEC plants at Clifty Creek and Kyger Creek were operated at a 45 percent and 50 percent capacity factor respectively in 2024.[3] These are relatively high utilization levels for older coal units with high operating costs. As discussed below, the OVEC plants also incurred high energy market losses in 2024. Utilities can minimize or avoid energy market losses through prudent economic commitment practices, which result in lower utilization rates for plants with high operating costs relative to newer, more efficient power plants. When plants such as these incur high energy market losses, that is an indication that the plants were being operated without regard for economic fundamentals (i.e., they were likely committed into the market with a "must-run" status, rather than allowing economically based commitment decisions by the system operator, PJM). The plants' high utilization and high energy market losses call into question the prudence of OVEC's operational practices.

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[1] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2024 (Pg. 1).

[2] Commission Order dated May 13, 2021, in Case No. U-20529, Pg. 17.

[3] U.S. Energy Information Administration (EIA) Form EIA-923 2024 Monthly Generation and Fuel Consumption.

Q For what portion of OVEC is I&M responsible?

A I&M's share of the ICPA with OVEC is 7.85 percent.[4] This means that I&M is responsible for 7.85 percent of OVEC's fixed and variable costs while also being entitled to a 7.85-percent share of OVEC's power output. This translates into an installed capacity share of 166 MW for January–December 2024.[5] The cost of the ICPA is passed through to I&M ratepayers as a direct cost.

Q Has I&M ever sought or received approval from the Commission for its decision to sign the ICPA?

A No. The Commission has found that the ICPA was not approved by the Commission, nor were the 2004 and 2010 amendments, which resulted in extending the ICPA through 2040.[6] The Clifty Creek and Kyger Creek Plants will each be 85 years old by the time the ICPA expires in 2040.[7]

ii. I&M pays above-market prices for the power it purchases from OVEC and passes the excess costs on to its customers

Q How does I&M serve customer load, and which associated costs are at issue in this reconciliation docket?

A I&M serves customer load through three types of resources: (1) generation assets owned (or leased) and operated by the Company, (2) power purchased under

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[4] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2024 (p. 1).
[5] Ex AG-3, I&M Response to AGSCCUB Request 1-12.
[6] Commission Order dated May 13, 2021, in Case No. U-20529, Pg. 13.
[7] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2024 (p. 1).

PPAs from generation assets owned by other entities or affiliates, and (3) PJM market power purchases.

For units owned or leased by I&M, the fuel costs associated with running the units are forecasted in PSCR dockets, recovered via the PSCR factor, and then reconciled in reconciliation dockets such as this one. All other operational costs are the subject of separate proceedings such as rate cases. For power purchased under PPAs, PSCR dockets serve to forecast the entire cost—rather than just the fuel costs—to operate the units generating the power. This cost is recovered directly from customers via the PSCR factor and then reconciled in reconciliation dockets such as this one. Since 2018, I&M's total PSCR costs have increased around 16 percent in real terms.[8]

Q What does it mean that I&M is paying OVEC above-market prices for power?

A If I&M can purchase the energy and capacity that it needs from the PJM market at a lower cost than it would pay to purchase power from OVEC under the ICPA, then it is paying above the market price for the OVEC power.

Q Is the ICPA delivering value to I&M ratepayers?

A No. In 2024, OVEC lost money on an energy basis. I&M was billed $29,300,859 or $37.37/MWh[9] for its energy and received only $24,786,980 or $31.61/MWh[10]

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[8] Calculated based on Exhibit IM-3, Page 1 of 4; Case No. U-21262 Exhibit IM-3, Page 1 of 4; Case No. U-21053 Exhibit IM-4, Page 1 of 4; Case No. U-20805 Exhibit IM-4, Page 1 of 4; Case No. U-20530 Exhibit IM-4, Page 1 of 4; Case No. U-20224 Exhibit IM-3, Page 1 of 4; Case No. U-20204 Exhibit IM-3, Page 1 of 4.

[9] I&M Response to AGSCCUB Request 1-10, Attachment 1.xlsx.

[10] I&M Response to AGSCCUB Request 1-11, Attachment 1.xlsx.

in energy market revenues. I&M admitted this itself in direct testimony submitted in this docket.[11] This gap resulted in energy losses of more than $4.5 million, which means the OVEC plants are not passing the lowest bar of economic operations in covering their fuel and variable operating costs with their energy market revenues. This also means that ratepayers would have been better off in 2024 if the OVEC plants had not operated—even taking into account that I&M would have to pay the demand charges regardless.

I&M stated that the plants' poor performances were due to a decline in PJM energy prices, not an increase in ICPA energy costs.[12] But ICPA energy charges for the past five years show an increasing trend. Specifically, I&M's energy costs jumped substantially in 2022 and remained at similar levels in 2023 and 2024. In 2022, the increased costs were masked by the abnormally high energy market revenues. But with energy market prices back to baseline levels, energy market revenue is no longer sufficient to cover the rising ICPA energy charges.

Q Is the ICPA delivering value to I&M ratepayers based on the total value of the services it provides?

A No. On a total value basis—that is taking into account both energy and capacity—the OVEC plants are costing substantially more than the value they provide. As a Sponsoring Company,[13] I&M was billed $82.31/MWh[14] under the ICPA for energy and demand charges[15] from OVEC. The power was only worth

[11] Direct Testimony of Jason Stegall, Pg. 12.

[12] *Id*.

[13] The owners of OVEC and their utility-company affiliates are considered Sponsoring Companies. Sponsoring Companies are each either a shareholder in the Company or an affiliate of a Shareholder in the Company, with the exception of Energy Harbor Corp.

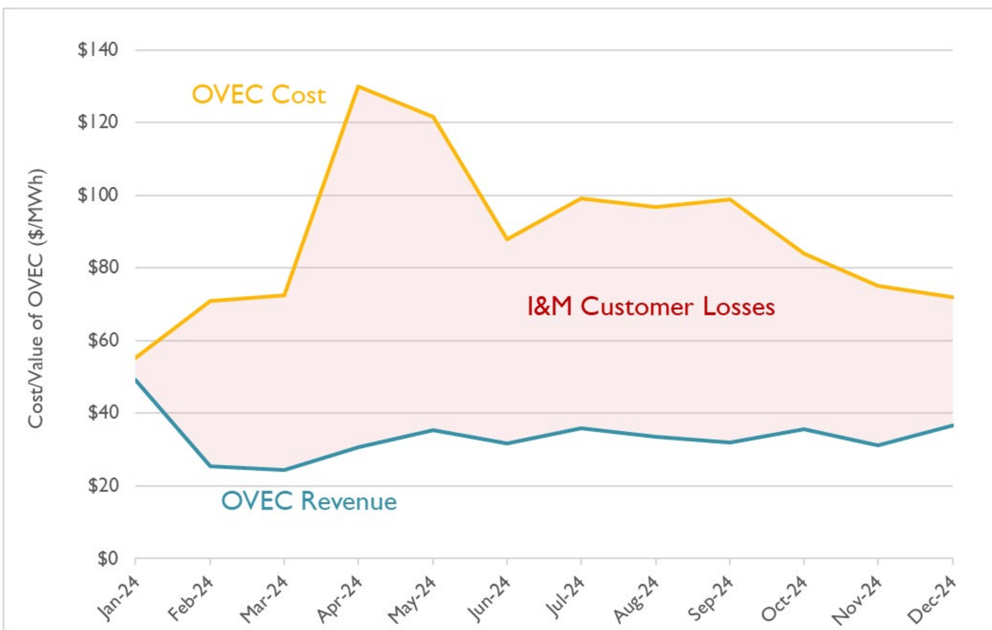
[14] I&M Response to AGSCCUB Request 1-10, Attachment 1.xlsx.

[15] I&M Response to AGSCCUB Request 1-11, Attachment 1.xlsx.

$34.02/MWh based on its value if I&M were to sell it into the PJM energy and capacity markets.[16]

Figure 1 below shows the $/MWh difference by month between the cost and value of OVEC's power. The shaded area in the middle shows the $/MWh cost premium that I&M customers are paying each month. This shows that in each month of 2024, I&M ratepayers were paying significantly more for OVEC services than the equivalent market value of the services.

Figure 1. All-in OVEC cost / value for energy and capacity (2024)



Source: I&M Response to AGSCCUB Request 1-10 Attachment 1 (monthly energy and demand charges, total MWh billed, Component C); I&M. Response to AGSCCUB 1-11 Attachment 1 (Energy revenues); Ex AG-5, 2024 State of the Market Report for PJM (p.316)(PJM $/MW-day capacity value):

[16] I&M Response to AGSCCUB Request 1-11, Attachment 1.; Ex AG-4, 2024 State of the Market Report for PJM (3): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec5.pdf.

https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec5.pdf.

The total difference between what OVEC was charging I&M and the value of the power works out to a net loss of $37.9 million in 2024 that I&M customers are being asked to pay while receiving no additional value. The Michigan jurisdictional share of the total losses is $5.4 million.

Q How do you calculate the cost and value to ratepayers of OVEC?

A I&M provided the monthly billing from OVEC for 2024 which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[17] Based on this billing data, OVEC charged I&M $65,810,943 for 784,029 MWh of electricity, for an average cost of $83.94 per MWh. To isolate just the energy and demand charges, I removed the transmission and PJM expenses and fees and ancillary charges. This results in a total of $64,536,127 for an average cost of $82.31/MWh.

The Company also provided energy revenue data by month which showed that the Company earned $24,786,980 in energy market revenues from the sale of OVEC power into the PJM market.[18] That works out to an average energy value of $31.61/MWh. Using the installed capacity values for 2024 (166 MW in January–December),[19] I estimated a capacity value based on the weighted average value that I&M's share of OVEC capacity would receive in the PJM Base Residual Auction ("BRA"). This was $34.13/MW-day for the first half of 2024 and

[17] I&M Response to AGSCCUB Request 1-10, Attachment 1.
[18] I&M Response to AGSCCUB Request 1-11, Attachment 1.
[19] Ex AG-3, I&M Response to AGSCCUB Request 1-12.

$28.92/MW-day for the second half of the year.[20] This works out to an average capacity value of only $2.41/MWh. The combined energy and capacity value of OVEC's power in the PJM market at $34.02/MWh[21] is well below the cost OVEC is charging I&M for power under the ICPA.

Q How do the costs and value of the ICPA in 2024 compare to the cost and value of the power in recent years?

A The cost for power under the ICPA has been significantly above market value since at least 2017, with the only exception being 2022 when the war in Ukraine drove gas prices, and therefore market prices, up to record-high levels. As shown in Table 2 below, net losses under the ICPA are not a new occurrence or a single-year fluke. It is in fact part of a pattern of poor and steadily worsening performance. And as I&M's latest PSCR plan filing in Case U-21596 shows (and my testimony in that docket discusses) the cost of OVEC power is projected to jump significantly going forward.[22]

[20] Ex AG-4, 2024 State of the Market Report for PJM (p.316): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec5.pdf.

[21] I&M Response to AGSCCUB 1-11, Attachment 1; Ex AG-4, 2024 State of the Market Report for PJM (p.316): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec5.pdf.

[22] Direct Testimony of Devi Glick, Case U-21596.

Table 2. OVEC power costs billed to I&M and market value (2017–2024) ($Nominal)

	MWh electricity	Total OVEC charges billed to I&M	Total market value	$/MWh cost	$/MWh value	Net cost/value
2017	937,620	$50,371,649	$35,170,074	$53.72	$37.51	($15,201,575)
2018	958,430	$51,213,688	$41,651,917	$53.43	$43.46	($9,561,770)
2019	926,846	$51,524,985	$32,432,962	$55.59	$34.99	($19,092,024)
2020	721,476	$47,665,070	$20,999,741	$66.07	$29.11	($26,665,329)
2021	790,000	$51,934,879	$36,156,634	$65.74	$45.77	($15,778,245)
2022	867,246	$59,996,210	$66,740,091	$69.18	$76.96	$6,743,881
2023	752,148	$60,784,471	$26,290,619	$80.81	$34.97	($34,493,852)
2024	784,029	$65,810,943	$26,675,502	$83.94	$34.02	$(39,135,441)

Source: Case U-21596, Direct Testimony of Devi Glick, Pg. 24 (power costs billed to I&M 2017 to 2023); Case U-21428 I&M Response to AGSCCUB 1-10 AG 1-10 Attachment 1 (2024 MWh billed and total OVEC charges billed to I&M); AGSCCUB 1-11 Attachment 1 (energy revenues); 2024 State of the Market Report for PJM (p.316)(PJM $/MW-day capacity value).

Q The PJM capacity auction cleared at a record-high price for the 2025/2026 and 2026/2027 delivery year. Is that likely to make the overall value of OVEC power positive in the future?

A No. OVEC power is expensive relative to alternatives even when using the 2025/2026 and 2026/2027 high capacity value. Specifically, capacity prices cleared at $269.92/MW-day for 2025/2026 and $329.17/MW-day[23] for 2026/2027, up from $28.92/MW-day in the last capacity auction.[24] This is a reflection of the tightening capacity market and the increase in demand for power

[23] PJM 2026/2027 Base Residual Auction Report, July 22, 2025. Available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

[24] PJM 2025/2026 Base Residual Auction Report, July 30, 2024. Available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx.

driven by data centers and large-load customers. But those capacity prices—which reflect this increased demand—are still far below the OVEC demand charge, which works out to an average of $581.54/MW-day. As I will discuss further below, even if OVEC's capacity was valued at the 2025/2026 or 2026/2027 clearing price for all of 2023, OVEC's power cost would still exceed its market value. This is due to not only its high demand charge but also its high energy charges, which as discussed above, exceeded its energy market revenues.

Q How do you respond to Company Witness Stegall's discussion of PJM's projected capacity shortfalls?

A It is not I&M and the I&M ratepayer's obligation to maintain system resources that cannot economically serve native demand for the sake of enhancing reliability in PJM. PJM is a regional entity serving 67 million people across 13 states and the District of Columbia. While reliability in PJM is paramount and important to I&M customers, it alone should not justify maintaining the OVEC plants. These plants are still some of the most expensive resources out there and even record demand growth cannot change that.

Q What do you conclude with respect to the ICPA and the services that I&M ratepayers receive from the contract?

A Based on I&M's own data I find that under the ICPA, in 2024 alone, billed energy and capacity charges cost I&M customers $37.9 million more than the market price for the same amount of energy and capacity. This means that ratepayers would have been better off in 2024 if I&M did not purchase power from OVEC and instead purchased energy and capacity from the market.

iii. A reasonable price to pay for power under the ICPA should be measured based on the cost billed for similar services or the cost of replacement resources

Q Has I&M provided any reasonable comparators for the value of the energy and capacity provided by OVEC?

A No. In earlier cases in which these costs were at issue, I&M refused to provide any comparators for the value of the power it received under the ICPA. In the 2021 PSCR Plan docket, the Commission ordered I&M to "provide a justification of its costs under the ICPA in its reconciliation of its 2021 PSCR plan"[25] and indicated that it will "look to comparisons with other long-term supply options as informative as to whether this particular contract adheres to the requirements of the Code of Conduct."[26]

I&M has proposed to compare the cost of OVEC to two of its own renewable resources that were the product of all-source Request for Proposals in Michigan issued in 2022—the Mayapple solar facility and the Lake Trout solar facility.[27] The Company also proposed the transfer price published by the Commission in Docket U-15800.[28] But as the Company itself acknowledges, the Commission has not accepted any of these proposed comparators, as none of these present reasonable comparators for the services under the ICPA.

In the current docket, I&M proposed TES Filer City Generating Station, a small 73 MW steam-fired cogeneration facility in Filer Township near Manistee, MI. The Filer City plant is not a relevant benchmark for the OVEC plants for a few

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[25] Commission Order dated November 18, 2021 in Case No. U-20804, Pg. 26.
[26] *Id.,* Pg. 18–19.
[27] Direct Testimony of Company Witness Jason Stegall, Pg. 21.
[28] *Id.*, Pg. 21–22.

reasons. First, Filer City is much smaller than the OVEC plants, at 73 MW compared to Kyger Creek at 1,086 MW and Clifty Creek at 1,303 MW plant. Second, Filer City is no longer operated as a baseload plant. In Case No. U-21407, the Commission approved an amendment to the Filer City PPA that "provides for the Filer City plant to be converted from must-run, baseload generation facility to an economically dispatchable facility . . ."[29] Third, in addition to burning coal, Filer City burns natural gas and wood waste, and I am advised by counsel that Filer City receives special, additional payments under a Michigan statute on account of being a merchant plant that burns wood waste.[30]

Q What metrics can be used to provide reasonable benchmarks of the value of capacity and energy provided by the OVEC units?

A There are several reasonable long-term supply comparisons we can use to evaluate whether the costs charged under the ICPA are reasonable and compliant with the MPSC Code of Conduct. These include: (1) The costs billed or paid by other entities for *similar services* provided under short- and long-term PPAs; (2) the cost of replacement capacity resources as represented by Cost of New Entry (CONE); (3) the gross avoidable cost of existing generation for a typical PJM coal plant; (4) the cost of replacement capacity and energy resources as represented by responses to requests for proposals (RFP) and other Company information; and (5) the PJM short-term capacity and energy market. Table 3 below summarizes the alternative benchmarks discussed in this section on a $/MWh basis and calculates the total excess costs incurred under the ICPA relative to each benchmark.

[29] Case No. U-21407, Order, July 7, 2023, p. 1.
[30] I am advised that the statutory sections are MCL 460.6a(9)-(11).

Q Have you made any updates to your benchmark analysis from prior dockets?

A Yes, based on the Commission order in Case No. U-21053,[31] I have continued to remove Component C of the Demand charge of the ICPA, which covers total expenses for taxes not included in Component A, B, or D (Accounts 408, 409, 411), in calculating the excess costs incurred relative to the Michigan Public Power Agency (MPPA) arrangements. I removed this component in the benchmark analysis because the Commission found that "it is reasonable to remove the effect of taxation from the ICPA since the MPPA is a tax-exempt entity whereas the company is not."[32] The taxes were not removed for any other benchmark comparisons.

Q Has I&M proposed any other modifications to the benchmark?

A Yes. In Docket U-21262, I&M witness Stegall claimed that the MPPA's billed costs for Cambell Unit 3 and Belle River don't reflect the initial investments that MPPA made to acquire its ownership share in the plants. He asserted that these should be accounted for in the benchmark analysis without putting forward a proposal of how to do so. The Commission did not find this concern compelling and did not address it in its final order.

In the current docket, I&M witness Stegall proposes that the Commission exclude the entire debt service costs from the benchmark calculations.[33]

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[31] Case No. U-21053, Final Order. September 26, 2024.
[32] *Id.,* Pgs. 11-12.
[33] Direct Testimony of Company Witness Jason Stegall, Pg. 27.

Q Is the Company's proposal to remove the entire debt service supported by the record?

A No, this proposal is unsupported by anything the Company has provided in the record in this case.

First, the debt service doesn't just include costs that are apples to apples with the upfront payments that MPPA made for its share of Campbell 3 and Belle River; it also includes non-upfront payments and costs incurred from sustaining capital expenditures and environmental expenditures at the plants over the years. What's more, all investments at Campbell 3 and Belle River are subject to Commission oversight and approval and scrutiny of the prudence of the investments. The same cannot be said for investments at the OVEC plants. By removing the entire debt service, all the debt associated with unscrutinized capital investments would also be removed. These same costs *are* included in the benchmarks for Campbell 3 and Belle River so there is no justification for removing them. And the Company has not attempted to isolate or quantify these costs from either the demand charge for OVEC or the bills for MPPA.

Second, the upfront payments that MPPA made for its share of the plants were made in 1980 and 1983—more than 40 years ago. And these costs are being paid for by MPPA's customers. But I&M has not put forward any information on how much of a plant balance remains, the rate of return, and the cost to MPPA ratepayers. Once again, without any specific data on the cost to MPPA ratepayers associated with this initial capital investment, and the equivalent cost for OVEC, the Commission should reject I&M's proposal to disallow the entire debt service.

Table 3. OVEC cost benchmarks for 2024 ($2024)

	Capacity cost ($/MWh)	Energy cost ($/MWh)	Total cost ($/MWh)	Excess costs based on benchmark ($Million)
OVEC PSCR cost[1]	$44.94	$37.37	$82.31	NA
Cost of similar services				
MPPA billing from Consumers Energy for Campbell Unit 3[2]	$9.50	$28.03	$37.53	$33.75
MPPA billing from DTE for Belle River[2]	$14.34	$54.95	$69.29	$8.85
Value of CONE & PJM BRA				
CONE – combined-cycle plant coming online in 2026[3]	$34.33	$27.03	$61.35	$17.71
Gross avoidable cost for existing generation – Coal[4]	$11.89	$55.34	$67.24	$13.09
Gross avoidable cost for existing generation – CC[4]	$8.07	$31.26	$39.33	$34.97
Gross avoidable cost for existing generation – CT[4]	$23.03	$39.56	$62.59	$16.74
PJM base residual auction (BRA)[5]	$2.41	$37.37	$39.78	$34.62

Sources: (1) I&M Response to AGSCCUB Request 1-10 Att. 1 (energy and demand costs); (2) Ex AG-5, Benchmark Cost for ICPA from Stegall Testimony Table JMS-2 (MPPA Campbell and Belle River energy and demand costs); (3) Brattle PJM CONE Study, 2022, https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx (CC levelized cost of new entry, heat rate, net summer installed capacity); (4) Ex AG-6, Gross Avoidable Costs for Existing Generation, Prepared for PJM by Brattle Group. January 9, 2023, https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2023/20230113-special/brattle-sl-pjm-acr-report.ashx (variable and fuel O&M costs); (5) 2024/2025 BRA Results, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx, (PJM $/MW-day capacity value).

Q How does the cost of power under the ICPA compare to the billed costs for other similar long-term PPAs?

A As seen in Table 3, the cost of power under the ICPA is much higher than the cost paid for power under several similar long-term PPAs in the region. I reviewed

MPPA Operating expenses[34] for annual expenses and revenues billed from DTE for Belle River and from Consumers for J.H. Campbell 3. I calculated the average cost billed for power charged for each unit. I find that in 2024, Consumers Energy billed MPPA an average of $37.53/MWh for power purchased from J.H. Campbell 3 and DTE billed MPPA an average of $69.29/MWh for the power purchased from Belle River. These charges covered the fuel and operations and maintenance ("O&M") expenses, administration and generation costs, and depreciation expenses from similar thermal resources and provided both energy and capacity to MPPA. Note I excluded transmission costs and MPPA administrative costs, as they are not included in the base energy and demand charges of the ICPA. This results in excess costs of $33.75 million and $8.85 million respectively for Campbell Unit 3 and Belle River relative to the value of the ICPA.

Q What is CONE and how does the value of CONE compare to the cost paid under the ICPA?

A CONE is a conservative measure of value that represents the cost of building new gas-fired generation capacity. If I&M were capacity-constrained, the capacity portion of the ICPA could be valued at PJM's CONE for the short term. The PJM value of CONE for a new combined-cycle unit is $502/MW-Day (in $2026) for the capacity cost.[35] To find the capacity cost in $/MWh, I first multiplied the $/MW-Day CONE values by the MW of a representative combined-cycle gas plant and then multiplied that by 365 days in a year. I then found the total annual MWh for a

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[34] Stegall Direct Testimony Table JMS-4: MPPA Operating Expenses vs ICPA; *See also*, MPPA 2024 Financial Statement, December 31,2024, Pg. 38-39.

[35] Ex AG-7, Brattle PJM CONE 2026/2027 Study, April 2022, https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

new combined-cycle plant based on the average annual capacity factor of 64 percent,[36] and the representative plant size from the CONE report.[37] I divided the total cost by total MWh to get a capacity cost per MWh.

For the energy cost, I calculated total annual MWh for a representative new combined-cycle plant based on Brattle's heat rate and plant size assumptions,[38] and an average annual capacity factor of 64 percent. For natural gas prices, I used I&M's forecast for the TCO Delivery point from AEP's July 2023 fundamental forecast.[39] Brattle didn't break out non-fuel variable costs in the CONE report, so I relied on the costs from the gross avoided cost of generation report (discussed below). Brattle assumes that all plants have firm gas contracts, so those costs are already included in the capacity cost. I added together the total capacity and energy cost to get a total cost. This works out to a total value of $61.35/MWh based on CONE of a new combined-cycle unit. This conservative measure of CONE for a new combined-cycle unit is far below the cost of OVEC.

Q For context, how does the value of CONE compare to the capacity price from PJM's current capacity auctions?

A CONE is much higher than the cleared capacity value (auction price) from PJM's most recent auctions. As discussed above, capacity prices cleared at $269.92/MW-

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[36] U.S. Energy Information Administration. 2023. "Natural gas combined-cycle power plants increased utilization with improved technology." *Today in Energy*. Available at https://www.eia.gov/todayinenergy/detail.php?id=60984.

[37] Ex AG-7, Brattle PJM CONE 2026/2027 Study, April 2022, https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx. Table 4.

[38] Ibid, Table 4.

[39] Case No. U-21427, I&M Response to Sierra Club Request 1-5, SC 1-5 Attachment 1.

day in the auction for 2025/2026 and $329.17/MW-day[40] for 2026/2027.[41] But even at this level, it is still far below the OVEC demand charge, which works out to an average of $581.54/MW-day. Further, although the market is capacity-constrained in the near term based on high demand from data center load, high capacity market prices are not expected to be sustained beyond the near term; instead, they should send a signal to the market to build more capacity and increase utilization of existing supply- and demand-side resources.

Q What is the gross avoidable cost for existing generation in PJM and how does it compare to the costs paid under the ICPA?

A The gross avoidable cost is a resource-specific, bottom-up cost estimate of the gross fixed cost associated with operating a representative plant.[42] PJM calculates an updated gross avoidable cost rate (ACR) every four years and uses it to determine default offer thresholds for the capacity market.[43] The ACR's purpose is to mitigate market power in the PJM capacity market. Previously, offer caps were set based on Net CONE (with various adjustments), but in 2021 the Federal Energy Regulatory Commission ("FERC") found the rates to be unrealistically high and switched to the ACR.[44] The 2023 report contains ACRs for nuclear,

[40] PJM 2026/2027 Base Residual Auction Report, July 22, 2025. Available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

[41] *PJM 2025/2026 Base Residual Auction Report*, July 30, 2024. Available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx.

[42] *Gross Avoidable Costs for Existing Generation*, Prepared for PJM by Brattle Group. January 9, 2023, page iii. Available at https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230223/20230223-item-02---4-brattle-gross-avoidable-costs-for-existing-generation-report.ashx.

[43] *Ibid.*

[44] *Id.*, Pg. 6.

coal, natural gas combined-cycle and combustion-turbine units, oil and gas steam turbined units, onshore wind, and solar PV.[45] In Table 3 I present the ACRs for a coal plant, combined-cycle unit, and combustion-turbine unit here to show the $/MW-day cost of a representative existing coal plant and combustion-turbine plant.

Q What are your conclusions regarding a benchmark for the power purchased from OVEC under the ICPA?

A The power I&M purchased under the ICPA is high cost by any reasonable measure. I have presented a number of reasonable alternatives in this section for current fossil resources contracted under similar PPAs, for new fossil resources, and for PJM market prices that demonstrate this point. Yet I&M customers are paying as much as $30 million per year in excess of the cost of these long-term supply comparisons.

iv. <u>I&M is free to continue purchasing power from OVEC as a matter of business; but if the costs are not prudently incurred, I&M is not entitled to recover the costs from Michigan ratepayers</u>

Q Has the Commission ordered I&M to undertake any efforts to reduce its power costs or renegotiate its contract with OVEC?

A Yes. In Case U-20529, the Commission stated in its final order that "it will expect to see evidence that the Company has taken steps to minimize the cost of [power], including efforts to renegotiate contracts…"[46] In the subsequent PSCR case, Case

[45] *Id.,* Pg. v.
[46] Commission Order dated May 13, 2021, in Case U-20529, Pg. 18.

U-20804, the Commission reiterated this directive for I&M to seek to renegotiate the contracts. The Commission also issued a Section 7 warning, notifying I&M in this docket that "the Commission is unlikely to permit the utility to recover these uneconomic costs from its customers in rates, rate schedules, or PSCR factors established in the future without good faith efforts to manage existing contracts such as meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers."[47] In Case No. U-21052, the Commission stated in its final order that I&M should "uphold its obligations to assess its existing contracts as market conditions or other factors change over time and to pursue amendments or new contractual agreements that may include taking meaningful steps to renegotiate provisions of the ICPA."[48] The Commission issued a Section 7 warning in that case[49] and again in cases U-21261[50] and U-21427.[51]

Q Did I&M undertake any efforts to minimize the cost of OVEC power, including attempting to renegotiate the ICPA contract?

A Only minimally. I&M President and COO Steven F. Baker sent a letter to OVEC in January of 2022 outlining the Commission orders listed above and "requesting that OVEC commence renegotiation discussions with I&M in a manner to reduce costs for I&M." OVEC responded that I&M would need to obtain consent from every other sponsoring Company to modify the ICPA. OVEC also indicated that it would need FERC approval, regulatory approval by state utility commissions,

[47] Commission Order dated November 18, 2021, in Case U-20804, Pg. 20.
[48] Commission Order dated June 22, 2023, in Case U-21052, Pg. 20.
[49] *Id.,* Pg. 21.
[50] Commission Order, Date May 23, 2025, in Case U-21261, Pg. 21.
[51] Commission Order, Dated October 10, 2024, in Case U-21427, Pg. 15.

and advance consent from counterparties to OVEC's debt arrangements to modify the contract.[52]

I&M indicated that in September 2023 Mr. Baker sent another letter to OVEC to engage other Sponsoring Companies in renegotiation discussions, and "take all possible steps to reduce costs under the ICPA."[53] And subsequently in January 2024 the Company sent another letter to the OVEC Board of Directors indicating its intention to sell the portion of the ICPA associated with the Michigan jurisdiction. I&M indicated that it received no correspondences from the Board or any Sponsoring Companies.[54]

Earlier this year, I&M did seek approval from the Indiana Utility Regulatory Commission to transfer its Michigan share of the OVEC energy and capacity to its Indiana ratepayers. The Commission approved this transfer in July, 2025.[55] I&M cited this transfer as a meaningful step to manage ICPA costs for Michigan customer.[56]

There is no indication that I&M took any operational steps to reduce how much the plants were self-scheduled or otherwise influence the day-to-day operations of the OVEC plants in a way that would reduce ratepayers costs. They have simply shifted the power to another state and made it the problem of the Indiana ratepayers.

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[52] Direct Testimony of Jason Stegall, Pg. 18.
[53] Cause No. 21262, Direct Testimony of Jason Stegall, Pg. 15.
[54] Direct Testimony of Jason Stegall, Pg. 19.
[55] IURC Order, Cause No. 45164 RA 5, p 17.
[56] Case No. 21596, Indiana Michigan Power Company's Exceptions to Proposal for Decision. September 19, 2025.

Q Are you recommending that the Commission tell I&M how it should be operating the OVEC plants?

A No. I&M has made clear in multiple dockets that it does not have the authority to unilaterally change how the OVEC units are operated and therefore has limited power over plant operations. Specifically, Company Witness Stegall says that while the Company can provide input into the procedures OVEC follows to operate the units, "I&M is one vote of the many needed to effectuate management or operational decisions because I&M cannot unilaterally force OVEC to do anything."[57]

While this might be true, it does not mean that I&M is totally powerless, and it does not give I&M the right to pass on to ratepayers any and all costs incurred to operate and manage the OVEC plants. The Commission agreed with this sentiment in a prior order. Specifically, in the final order in Case U-20530, the 2020 Reconciliation docket, the Commission stated "I&M, of course, remains free to continue to make whatever business decisions it wishes in terms of continuing to participate in the ICPA. What it cannot do is continue to recover the costs of any unreasonable and imprudent decisions from its customers."[58]

Q What are your recommendations to the Commission regarding the OVEC units?

A I am recommending that the Commission once again disallow costs incurred by I&M to operate the OVEC plants that are passed on to Michigan ratepayers. Specifically, the Commission should disallow in this proceeding $5.4 million, which is Michigan's jurisdictional share of the total $37.9 million in excess

[57] Case No. U-20805, Direct Testimony of Witness Stegall, Pg. 5.

[58] Commission Order dated February 2, 2023 in Case U-20530, Pgs. 12–13.

compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services). This represents the difference between what I&M charged customers for OVEC power, and the equivalent price that I&M would pay to procure the energy and capacity from the PJM market in 2024.

Alternatively, using MPPA's contract for Campbell Unit 3 and Belle River as a benchmark, with each weighted based on generation, I find that ICPA power exceeds the cost of benchmarks by $18.12/MWh (Table 4). Multiplying the $/MWh cost difference between the ICPA and the Campbell and Belle River benchmarks in 2024 by the ICPA MWh in 2024, I find that I&M paid around $14.2 million in excess costs for the ICPA in 2024. Of that, $2.03 million is Michigan's share.[59]

Table 4. ICPA excess costs relative to benchmarks in 2024 ($2024)

	MWh	Contract cost $	$/MWh
Weighted average benchmarks	1,311,345	$81,914,595	$62.47
Campbell Unit 3	281,882	$10,579,232	$37.53
Belle River	1,029,463	$71,335,363	$69.29
ICPA	784,029	$63,179,467	$80.58
Excess cost	784,029	$14,204,225	**$18.12**
Michigan share		**$2,025,523**	

Source: I&M Response to AGSCCUB Request 1-10 Att. 1 (ICPA energy and demand charges, MWh billed); Ex AG-5, Direct Testimony of Stegall Table JMS-2: Benchmark Cost for ICPA (MPPA Campbell and Belle River costs, MWh and Michigan Jurisdictional ratio) .

[59] Our calculation of Michigan's share of excess OVEC costs incurred under the ICPA differs from the $2,016,495 that Stegall calculates in his testimony (Table JMS-3 on pg. 25). Stegall includes MISO RTO costs in his calculation of total MPPA contract costs for Campbell and Belle River but he does not include PJM RTO costs in the ICPA calculations. In order to make an apples-to-apples comparison between the MPPA contract costs and the ICPA contract, I added PJM expenses/fees (I&M Response to AGSCCUB 1-10 Attachment 1) back into my calculation of the ICPA total cost. This accounts for the cost difference of $9,028.

4. I&M ALSO PAID EXCESS AND ABOVE-MARKET COSTS TO AEG FOR POWER FROM ROCKPORT IN 2023

i. Overview of Rockport Unit 1

Q Provide an overview of the Rockport Generating Station.

A The Rockport Generating Station is a two-unit coal-fired power station located in Spencer County, Indiana. I&M operates the plant. Unit 1 has a nameplate capacity of 1,320 MW and is 50-percent-owned by I&M and 50-percent-owned by AEG. Unit 2 was previously owned by non-affiliated parties and leased back to I&M and AEG. This lease expired in December 2022. Since that time, Rockport Unit 2 has been operated as a merchant facility and all related costs are excluded from this reconciliation docket.

AEG currently sells 100 percent of its share of Rockport Unit 1 back to I&M.

Q How often was Rockport used in 2024?

A The Rockport units operated at only a 22 percent capacity factor in 2024.[60]

Q What portion of Rockport Unit 1's costs is I&M responsible for and how are those costs passed on to its ratepayers?

A I&M is responsible for 100 percent of the costs associated with Rockport Unit 1.

For the 50-percent share of Rockport Unit 1 that it owns, I&M plans for and recovers the associated fuel and consumable costs in PSCR dockets. These costs are passed on directly to customers as fuel costs through fuel clauses and are

[60] EIA Form 923 and EIA Form 860.

reconciled in the current docket. The remaining (non-fuel) unit costs are passed on to ratepayers through rate cases and other dockets.

For the 50-percent share of Rockport Unit 1 that AEG owns, I&M pays for the power through the UPA. Because this power is procured through a PPA, instead of from a unit operated by I&M, the entire cost of this share is passed on directly to customers through fuel clauses (not just the fuel costs). That means the entire PPA cost is forecasted and planned for in this PSCR docket.

ii. I&M paid excessive and above-market costs for power from Rockport to its affiliate AEG in 2024

Q What did I&M pay under the UPA to purchase Rockport Unit 1 power from AEG in 2024?

A I&M purchased 1,476,405 MWh of Rockport power from AEG in 2024 for a total cost of $125,675,469.[61] That comes out to $85.12/MWh.[62]

Q Under what agreement did I&M make these purchases?

A I&M purchased power from Rockport Unit 1 under the UPA with AEG dated March 31, 1982, and an amendment dated May 8, 1989.[63]

Q Are I&M and AEG affiliates?

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[61] I&M only provided energy and capacity values. This does not include transmission charges and PJM expenses and fees.

[62] I&M Response to AGSCCUB Request 1-9, U-21428 AG 1-9 Attachment 1.

[63] Ex AG-8, Unit Power Agreement

A Yes. Both AEG and I&M are subsidiaries of AEP. I am advised by counsel that Rule 8(4) of the MPSC Code of Conduct's affiliate price cap would apply to the AEG purchases just as it does to the OVEC purchases. Another affiliate relationship can be found in the fact that I&M operates the plant that produces the power that it buys from AEG. I am advised by counsel that in Case No. U-20530, the Commission held that the UPA is subject to Rule 8(4) of the Code of Conduct.[64]

Q What does the UPA require I&M to pay AEG?

A I&M is required to pay AEG an energy charge and a demand charge to receive the energy and capacity allotted to I&M from AEG's owned and leased shares of Rockport.[65] The demand charge includes a return on common equity ("ROE") to AEG.

Q What is the ROE that I&M pays to AEG?

A The ROE is set at 12.16 percent.[66]

Q Did the Commission approve the UPA or the amendment?

A Only partially. The Commission originally approved the inclusion of the capacity charges related to the purchase of Rockport Unit 2 capacity from AEG in a 1991 order.[67] But I&M has not identified any Commission Order approving charges related to the AEG share of Rockport Unit 1. In addition, I&M has not identified

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[64] Case No. U-20530, Commission Order dated February 2, 2023, Pg. 15.
[65] Ex AG-8, Section 1.3 of the UPA.
[66] Ex AG-9, Excerpt of FERC application concerning the UPA, ER19-717-000.
[67] Ex AG-10, Case No. U-20530, I&M Response to AG Request 2-29.

any Commission Order adjudicating the UPA's compliance with the MPSC Code of Conduct.

Q Has the Commission issued any direction to I&M in recent years regarding the purchases from AEG under the UPA?

A Yes. In 2019, the Commission issued an order in Case U-18404,[68] in response to a recommendation by the Attorney General regarding the ROE awarded to AEG. This order reiterated that I&M has an obligation to examine existing contracts as market conditions change and make good-faith attempts to negotiate and amend these contracts. Further, the Commission stated that I&M was expected to "demonstrate to this Commission, in the PSCR reconciliation proceeding and future plan cases, that its wholesale purchases from affiliates are just and reasonable under current market conditions… and that the utility is taking appropriate actions to minimize costs to ratepayers pursuant to Act 304."[69]

Q Has I&M attempted to compare the cost of the UPA to market prices or any other benchmarks in order to determine whether it complies with the affiliate price cap in the MPSC Code of Conduct?

A No. There was no mention of any benchmarks for Rockport in the Company's testimony.

Q How does the cost of the Rockport power purchased under the UPA compare to the market value of the power?

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[68] Commission Order dated June 7, 2019 in Case U-18404.

[69] *Id.*, Pgs. 7–8.

A In 2024, Rockport Unit 1 incurred losses for the 50-percent share it purchased from AEG. On a total value basis—that is taking into account both energy and capacity of AEG's share of Rockport Unit—I&M was billed a total of $85.12/MWh[70] under the UPA for energy and demand charges[71] from AEG's 658.8 MW[72] portion of Rockport Unit 1. The power was only worth $41.78/MWh based on its value if I&M were to sell it into the PJM energy and capacity markets.[73] This means that I&M customers are paying an estimated $43.34/MWh premium for Rockport Unit 1's energy and capacity services over the equivalent value of the energy and capacity in the PJM market. This works out to a total $64.0 million premium for AEG's portion of Rockport Unit 1's services allocated to I&M based on the UPA. Approximately $9.1 million of this will be passed on to Michigan customers in this reconciliation docket through the UPA and an equal amount through excess fuel costs recovered in this docket.

Q How did you calculate the cost of Rockport power from the AEG contract?

A I&M provided its bills from AEG for its share of Rockport Unit 1 for each month in 2024.[74] I calculated the energy charges for each month as the sum of fuel, purchased power, taxes, and fuel from the prior month's adjustment for both units. The remaining charges in the total bill reflect non-variable costs; I classified these as part of a demand charge.

[70] I&M Response to AGSCCUB Request 1-09, U21428 AG 1-9 Attachment 1.
[71] I&M Response to AGSCCUB Request 1-09, U21428 AG 1-9 Attachment 1.
[72] Ex AG-11, I&M Response to AGSCCUB 1-22.
[73] Ex AG-4, 2024 State of the Market Report for PJM (3): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec5.pdf.
[74] I&M Response to AGSCCUB Request 1-09, U-21428 AG 1-9 Attachment 1.

Q How does the cost of the Rockport power from the AEG contract compare to the other long-term supply benchmarks that you discussed earlier in your testimony?

A It exceeds all of them. In fact, it is more than twice as much as any of the other supply options I benchmarked. I compared the price of power I&M paid for AEG's share of Rockport Unit 1 under the UPA to the benchmarks I provided in Section 3 for MPPA's purchase of power from Campbell Units 3 and Belle River (Table 5). On an energy basis, I&M earned $22.9 million; however, demand charges outweighed those gains by more than double, resulting in a net loss when considering total costs. I find that I&M paid more than $30.2 million in excess costs under the UPA; the Michigan share of excess costs was $4.3 million.

Table 5. UPA excess costs relative to benchmarks in 2024 ($2024)

	MWh	Contract cost $	$/MWh
Weighted average benchmarks	1,311,345	$81,914,595	$62.47
Campbell Unit 3	281,882	$10,579,232	$37.53
Belle River	1,029,463	$71,335,363	$69.29
UPA	1,476,405	$122,382,413	$82.89
Excess cost	1,476,405	$30,157,164	$20.43
Michigan share		$4,300,412	

Source: I&M Response to AGSCCUB Request 1-09 U-21428 AG 1-9 Att. 1; Ex AG-5, Direct Testimony of Stegall Table JMS-2 Benchmark Cost for ICPA (MPPA Campbell and Belle River costs, MI Jurisdictional share ratio).

The Commission should continue to compare the cost of the Rockport power under the UPA to the cost of other long-term supply resources.

Q **What are your recommendations to the Commission regarding I&M's payment to AEG under the UPA?**

A The Commission should disallow in this proceeding $9.1 million, which is Michigan's jurisdictional share of the total $64.0 million in excess compensation that I&M paid AEG for power from Rockport services under the UPA (relative to the market value of the services). This represents the difference between what I&M charged customers for Rockport power purchased from AEG power, and the equivalent price that I&M would pay to procure the energy, capacity, and ancillary services from the PJM market in 2024.

Q **Does this conclude your testimony?**

A Yes.

Devi Glick, Senior Principal

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, S. Kwok, J. Tabernero, R. Wilson. 2021. *A Clean Energy Future for Tampa.* Synapse Energy Economics for Sierra Club.

Glick, D. *2021. Synapse Comments and Surreply Comments to the Minnesota Public Utility Commission in response to Otter Tail Power's 2021 Compliance Filing* Docket E-999/CI-19-704. Synapse Energy Economics for Sierra Club.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Glick, D., J. Frost, B. Biewald. 2020. *The Benefits of an All-Source RFP in Duke Energy Indiana's 2021 IRP Process.* Synapse Energy Economics for Energy Matters Community Coalition.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

New Mexico Public Regulation Commission (Case No. 19-00099-UT / 19-00348-UT): Direct Testimony of Devi Glick in the matter of El Paso Electric Company's Application for Approval of Long-Term Purchased Power Agreements with Hecate Energy Santa Teresa, LLC, Buena Vista Energy, LLC, and Canutillo Energy Center LLC. On Behalf of New Mexico Office of the Attorney General, January 23, 2023.

Arizona Corporation Commission (Docket No. E-01933A-22-0107): Direct Testimony of Devi Glick in the matter of the application of Tucson Electric Power Company for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona for related approvals. On Behalf of Sierra Club. January 11, 2023.

New Mexico Public Regulation Commission (Case No. 22-00093-UT): Direct Testimony of Devi Glick in the amended application for approval of El Paso Electric Company's 2022 renewable energy act plan pursuant to the renewable energy act and 17.9.572 NMAC, and sixth revised rate no. 38-RPS cost rider. On Behalf of New Mexico Office of the Attorney General, January 9, 2023.

Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Cost §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilties Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated January 2023

ANNUAL REPORT — 2024

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 under a Department of Energy (DOE) Power Agreement. On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc.[1]	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Ohio Edison Company[1]	0.85
Ohio Power Company**[6]	4.30
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
The Toledo Edison Company[1]	4.00
	100.00

The Sponsoring Companies are each either a shareholder in the Company or an affiliate of a shareholder in the Company, with the exception of Vistra Vision. The Sponsoring Companies currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC[1]	3.01
Appalachian Power Company[6]	15.69
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Indiana Michigan Power Company[6]	7.85
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Monongahela Power Company[1]	0.49
Ohio Power Company[6]	19.93
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
Vistra Vision	4.85
	100.00

Some of the Common Stock issued in the name of:

*American Gas & Electric Company
**Columbus and Southern Ohio Electric Company

Subsidiary or affiliate of:
[1]FirstEnergy Corp.
[2]Buckeye Power, Inc.
[3]The AES Corporation
[4]Duke Energy Corporation
[5]PPL Corporation
[6]American Electric Power Company, Inc.
[7]Wolverine Power Supply Cooperative, Inc.
[8]CenterPoint Energy, Inc.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

A Message from the President

As we reflect on 2024, Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), navigated an energy market that, while still challenging, showed some signs of improvement. The first half of the year saw depressed energy demand, largely due to a persistent oversupply of natural gas and a milder-than-expected winter. However, we were encouraged to see natural gas prices increase in the fourth quarter, driven by a stronger-than-anticipated rebound in demand. Throughout the year, we also observed a continued tightening of margins in PJM capacity, especially with the potential for extreme weather in key months like January, July, and August. Our dedicated OVEC-IKEC team remained focused on preparing our units for future positive market shifts and any unforeseen grid events.

Looking forward to 2025 and beyond, the energy landscape is poised for significant transformation. The industry is anticipating a substantial surge in demand over the next five to ten years, primarily fueled by the explosive growth of data centers. This trend underscores the critical need for currently available baseload power. At OVEC-IKEC, we are unwavering in our commitment to being a reliable and available resource for our Sponsors and the broader market. Through our continued investments and compliance with environmental regulations, OVEC-IKEC's plants are strategically positioned to provide that vital baseload generation, ensuring we meet the energy market's evolving needs throughout the coming decade.

Even with these drastically changing markets, the OVEC-IKEC team continues to work hard on creating a zero-harm culture, focusing on environmental stewardship, and improving our cost and operations with continuous improvement.

SAFETY

OVEC-IKEC employees reached multiple safety milestones over the past year. In February 2025, Kyger Creek Plant completed two consecutive years without an OSHA Recordable injury. System Office Division, including Electrical Operations personnel, surpassed 10 years without an OSHA Recordable injury in April 2025. Companywide, as of May 2025, OVEC-IKEC had 1 DART (days away, restricted or transferred) year-to-date.

In an effort to continue advancing our company safety culture, OVEC's 2025 Strategic Plan Zero Harm Objective centers around two key initiatives: increasing the presence of leadership in the field by conducting safety observations, and integrating our strategic partners and contractors into our safety and health program. A focal point of the Company's field observation program is conducting quality observations where feedback is provided, and improvement opportunities are identified.

CULTURE

OVEC-IKEC remains on its continuous journey of culture improvement. The Company has conducted an annual survey since 2016 and continues to make improvements every year. OVEC-IKEC believes investing in culture improvement to engage our people will be the key to our long-term success. For 2024, our culture survey results saw improvements in all areas including recent focus areas around communication and accountability. For 2025, we will conduct another survey to allow our teams to continue to focus on opportunities and update their culture action plans to enable improvement.

RELIABILITY

In 2024, the combined commercial availability (CA) of the five generating units at Kyger Creek and the six units at Clifty Creek was 89.2 percent compared with 84.8 percent in 2023. The combined equivalent forced outage rate (EFOR) at both plants was 6.75 percent in 2024 compared with 5.76 percent in 2023. Through April 2025, the combined EFOR of the eleven generating units was 7.57 percent and CA of 88.9%.

ENERGY SALES

OVEC's use factor — the ratio of power scheduled by the Sponsoring Companies to power available — for the combined on- and off-peak periods averaged 74.5 percent in 2024 compared with 69.1 percent in 2023. The on-peak use factor averaged 78.7 percent in 2024 compared with 72.6 percent in 2023. The off- peak use factor averaged 69.1 percent in 2024 and 64.8 percent in 2023.

In 2024, OVEC delivered 10 million megawatt hours (MWh) to the Sponsoring Companies under the terms of the Inter-Company Power Agreement compared with 9.6 million MWh delivered in 2023. Weak natural gas prices and milder weather in 2023, resulted in lower demand. This trend continued throughout much of 2024 with some increase in natural gas prices and related energy demand in the fourth quarter.

POWER COSTS

In 2024, OVEC's average power cost to the Sponsoring Companies was $83.91 per MWh compared with $80.81 per MWh in 2023. The average power cost increase for 2024 was a result of higher demand costs related to environmental capital investments in bioreactor technology at both plants to comply with the 2020 Effluent Limitation Guidelines (ELG) rule.

2025 ENERGY SALES OUTLOOK

Strengthening demand and higher natural gas prices in the first quarter has impacted OVEC's generation in 2025. OVEC's use factor has improved significantly, as April YTD was 85.8% compared to 76.4% April YTD 2024. OVEC's updated projection for 2025, which assumes some continued stronger than expected energy demand through the end of the year, is projected at approximately 11 million MWh of generation.

COST CONTROL INITIATIVES

OVEC and IKEC employees remain committed to controlling costs and enhancing operational performance through the Company's continuous improvement process (CIP). Since its inception in2013, CIP has delivered over $38 million in sustainable savings by implementing more than 10,000 process improvements.

The success of CIP is rooted in its focus on employee engagement and the practical application of LEAN tools across the organization. Continued investment in skill development ensures that continuous improvement remains a core component of our culture and daily operations.

To further drive value, OVEC-IKEC has consistently utilized third-party support to challenge internal assumptions and uncover additional improvement opportunities. Business cases have been developed, and associated cost savings and revenue enhancement metrices are being tracked and realized.

ENVIRONMENTAL COMPLIANCE

OVEC-IKEC continues to maintain a strong commitment to meeting all applicable federal, state and local environmental rules and regulations. During 2024, OVEC operated in substantial compliance with the Mercury Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSAPR) and other applicable state and federal air, water and solid waste regulations. The Company is well positioned to continue to operate all SCR controlled units during 2025 in compliance with the NOx ozone season rules currently in effect.

Clifty Creek and Kyger Creek both continue to sell the majority of the gypsum produced at each plant into the wallboard market. Clifty Creek has also been successful in marketing fly ash, and OVEC anticipates that market will continue to grow longer term.

For compliance with the 2020 ELG rule, the Company met the initial applicability dates for bottom ash transport water, and expects to meet the applicability dates for FGD wastewaters in accordance with each plant's NPDES permits by finalizing construction of bioreactors and having them fully operational by December 31, 2025.

USEPA, under the Biden administration, proposed new Green House Gas (GHG) rules which became effective on July 8, 2024. The rule has been challenged by a number of states, trade groups, and the utility industry. In 2025, the Trump administration has public stated it will repeal and replace the 2024 GHG rule and is currently working on a replacement rule at this time.

In addition, the Trump Administration also announced its intention to reconsider the 2024 Supplement to the Steam Electric Effluent Guidelines as well as other 2024 environmental regulations implemented by the prior administration.

OVEC will continue monitoring regulatory and legislative initiatives that may impact the utility sector wastewater treatment, solid waste management and emissions as well as any other applicable regulatory and legislative initiatives throughout 2025.

In the interim, the Company continues to work toward executing its compliance strategies for complying with obligations associated with the 2015 CCR rule, the 2020 ELG Rules, and the Clean Water Act Section 316(b) regulations applicable to both facilities.

BOARD OF DIRECTORS AND OFFICERS CHANGES

On July 25, 2024, Mr. Subin Mathew, Director of Reliability and Grid Modernization, Indiana Michigan Power, was elected to the IKEC board. Mr. Mathew replaces Mr. David Isaacson, who resigned effective July 1, 2024.

On December 18, 2024, Mr. Craig Grooms, President and CEO of Buckeye Power and Ohio's Rural Electric Cooperatives, was elected a member of the OVEC and IKEC boards and appointed a member of the executive committees for OVEC and IKEC. Mr. Grooms replaces Mr. Patrick O'Loughlin. Mr. O'Loughlin served as a member of the OVEC and IKEC boards for 20 years.

On December 18, 2024, Mr. Matthew W. Fransen was elected Assistant Secretary and Assistant Treasurer of OVEC and IKEC, replacing Ms. Julie Sherwood, who resigned effective November 30, 2024.

Brian D. Sherrick

Brian D. Sherrick
OVEC-IKEC President

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2024 AND 2023

	2024	2023
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 3,272,178,716	$ 3,181,000,415
Less—accumulated provisions for depreciation	2,270,960,768	2,145,475,614
	1,001,217,948	1,035,524,801
Construction in progress	53,739,145	17,869,041
Total electric plant	1,054,957,093	1,053,393,842
CURRENT ASSETS:		
Cash and cash equivalents	44,178,533	39,734,708
Accounts receivable	46,946,724	65,061,157
Income taxes receivable	1,728,688	-
Fuel in storage	185,986,932	165,654,233
Materials and supplies	59,981,267	57,450,329
Property taxes applicable to future years	3,870,000	3,762,000
Regulatory assets	6,358,579	1,643,440
Prepaid expenses and other	6,575,226	4,655,934
Total current assets	355,625,949	337,961,801
REGULATORY ASSETS:		
Unrecognized postemployment benefits	9,464,083	8,808,588
Unrecognized pension benefits	5,492,094	2,178,707
Income taxes billable to customers	55,902,459	33,721,522
Other regulatory assets	2,771,867	4,415,307
Total regulatory assets	73,630,503	49,124,124
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	430,646	747,151
Long-term investments	216,975,904	191,373,359
Postretirement benefits	46,028,655	46,589,903
Other	1,865,000	2,865,000
Total deferred charges and other	265,300,205	241,575,413
TOTAL	$ 1,749,513,750	$ 1,682,055,180

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2024 AND 2023

	2024	2023
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2024 and 2023	$ 10,000,000	$ 10,000,000
Long-term debt	712,224,775	814,322,489
Line of credit borrowings	145,000,000	140,000,000
Retained earnings	32,589,284	28,429,819
Total capitalization	899,814,059	992,752,308
CURRENT LIABILITIES:		
Current portion of long-term debt	103,407,923	98,831,592
Current portion of line of credit borrowings	30,000,000	10,000,000
Accounts payable	61,336,547	70,075,957
Accrued taxes	12,414,121	17,040,414
Regulatory liabilities	49,100,028	847,054
Asset retirement obligations	39,992,049	19,724,090
Accrued interest and other	21,051,559	21,522,096
Total current liabilities	317,302,227	238,041,203
COMMITMENTS AND CONTINGENCIES (Notes 3, 9, 11, and 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	140,373,348	137,206,331
Advance billing of debt reserve	120,000,000	120,000,000
Total regulatory liabilities	260,373,348	257,206,331
OTHER LIABILITIES:		
Pension liability	5,492,094	2,178,707
Deferred income tax liability	22,285,974	22,206,478
Asset retirement obligations	233,858,657	159,350,630
Postemployment benefits obligation	9,464,083	8,808,588
Other non-current liabilities	923,308	1,510,935
Total other liabilities	272,024,116	194,055,338
TOTAL	$ 1,749,513,750	$ 1,682,055,180

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

	2024	2023
REVENUES FROM CONTRACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 4,131,774	$ 4,126,832
Ohio Valley Electric Corporation	-	-
Sponsoring Companies	790,040,646	850,874,742
Total revenues from contracts with customers	794,172,420	855,001,574
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	373,259,365	344,622,250
Purchased power	3,942,691	3,937,749
Other operation	94,822,339	88,025,177
Maintenance	116,666,625	92,064,829
Depreciation	133,804,423	256,096,220
Federal income tax	4,500,000	3,000,000
Taxes—other than income taxes	13,468,791	12,417,841
Total operating expenses	740,464,234	800,164,066
OPERATING INCOME	53,708,186	54,837,508
OTHER INCOME (EXPENSE)	971,769	197,576
INCOME BEFORE INTEREST CHARGES	54,679,955	55,035,084
INTEREST CHARGES:		
Amortization of debt expense	1,627,140	1,730,851
Interest expense	48,893,350	50,376,392
Total interest charges	50,520,490	52,107,243
NET INCOME	4,159,465	2,927,841
RETAINED EARNINGS—Beginning of year	28,429,819	25,501,978
RETAINED EARNINGS—End of year	$ 32,589,284	$ 28,429,819

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

	2024	2023
OPERATING ACTIVITIES:		
Net income	$ 4,159,465	$ 2,927,841
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	133,804,423	256,096,220
Amortization of debt expense	1,627,140	1,730,851
Changes in assets and liabilities:		
Accounts receivable	18,114,433	(14,349,799)
Fuel in storage	(19,294,505)	(103,279,667)
Materials and supplies	(2,530,938)	(10,666,098)
Property taxes applicable to future years	(108,000)	(600,000)
Prepaid expenses and other	(1,919,292)	1,738,977
Other regulatory assets	(23,165,211)	(3,250,410)
Other noncurrent assets	(18,976,761)	(17,491,921)
Accounts payable	(13,194,218)	(14,541,030)
Accrued taxes	(6,354,981)	6,114,877
Accrued interest and other	(4,186,824)	691,245
Other liabilities	(143,807)	(74,186,215)
Other regulatory liabilities	51,419,991	(45,321,625)
Net cash (used in) provided by operating activities	119,250,915	(14,386,754)
INVESTING ACTIVITIES:		
Electric plant additions	(41,124,451)	(50,822,921)
Proceeds from sale of long-term investments	588,917,379	933,946,766
Purchases of long-term investments	(587,769,571)	(848,379,837)
Net cash (used in) provided by investing activities	(39,976,643)	34,744,008
FINANCING ACTIVITIES:		
Debt issuance and maintenance costs	-	(689,458)
Repayment of Senior 2006 Notes	(29,367,184)	(27,726,072)
Repayment of Senior 2007 Notes	(20,965,069)	(19,773,778)
Repayment of Senior 2008 Notes	(23,499,340)	(22,023,544)
Repayment of Senior 2017A Notes	(25,000,000)	-
Proceeds from line of credit	60,000,000	40,000,000
Payments on line of credit	(35,000,000)	-
Principal payments under finance leases	(998,854)	(1,021,914)
Net cash (used in) provided by financing activities	(74,830,447)	(31,234,766)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,443,825	(10,877,512)
CASH AND CASH EQUIVALENTS—Beginning of year	39,734,708	50,612,220
CASH AND CASH EQUIVALENTS—End of year	$ 44,178,533	$ 39,734,708
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 50,065,094	$ 52,107,243
Income taxes (received) paid—net	$ 26,100,000	$ 9,700,000
Non-cash electric plant additions included in accounts payable at December 31	$ 3,548,581	$ 136,855

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements—The consolidated financial statements include the accounts of Ohio Valley Electric Corporation ("OVEC") and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation ("IKEC") collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization—The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility-holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement ("ICPA"), which has a current termination date of June 30, 2040. Approximately 20% of the Companies' employees are covered by a collective bargaining agreement that expires on August 31, 2027.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy ("DOE"). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power ("Arranged Power"), under the direction of the DOE, for resale directly to the DOE. The current agreement with the DOE was executed on July 11, 2018, for one year, with the option for the DOE to extend the agreement at the anniversary date. The agreement was extended on July 11, 2024, for one year. OVEC anticipates that this agreement could continue to 2027. All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs as well as earn a return on equity before federal income taxes. In addition, the proceeds from the sale of power are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost-plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred in the accompanying consolidated balance sheets and are recognized as income as the related amounts are included in service rates and recovered from or refunded to customers.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through the billings of Sponsoring Companies at December 31, 2024 and 2023, were as follows:

	2024	2023
Regulatory assets:		
Current regulatory assets—other regulatory assets	$ 6,358,579	$ 1,643,440
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	9,464,083	8,808,588
Unrecognized pension benefits	5,492,094	2,178,707
Income taxes billable to customers	55,902,459	33,721,522
Other regulatory assets	2,771,867	4,415,307
Total	73,630,503	49,124,124
Total regulatory assets	$ 79,989,082	$ 50,767,564
Regulatory liabilities:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ 48,440,700	$ -
Deferred credit—advance collection of interest	659,328	847,054
Total	49,100,028	847,054
Noncurrent regulatory liabilities:		
Postretirement benefits	140,373,348	137,206,331
Advance billing of debt reserve	120,000,000	120,000,000
Total	260,373,348	257,206,331
Total regulatory liabilities	$ 309,473,376	$ 258,053,385

Regulatory Assets—Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs, and income taxes to be billed to the Sponsoring Companies in future years. The Companies' current billing policy for pension and postemployment benefit costs is to bill its actual plan funding.

Regulatory Liabilities—The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2024 consist primarily of advance billing of construction and interest expense collected from customers in advance of expense recognition. These amounts will be credited to customer bills during 2025. Other regulatory liabilities consist primarily of postretirement benefit costs and advanced billings collected from the Sponsoring Companies for debt service.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The regulatory liability for postretirement benefits recorded at December 31, 2024 and 2023, represents amounts collected in historical billings in excess of net periodic benefit costs recognizable under accounting principles generally accepted in the United States of America (“GAAP”), including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental net plan assets recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs.

Beginning January 2017 and continuing through December 31, 2020, the Companies billed the Sponsoring Companies for debt service as allowed under the ICPA. A total of $120 million was billed during this period. As the Companies have not yet incurred the related costs, a regulatory liability was recorded which will be credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant—Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service, if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue—advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies—The Companies maintain coal, reagent, and oil inventories for use in the generation of electricity. Additionally, the Companies maintain emission allowance inventories for regulatory compliance purposes. These inventories are valued at average cost. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments—Long-term investments consist of marketable securities and other investments that are held for the purpose of funding decommissioning and demolition costs, debt service, potential postretirement funding, and other costs. These debt securities have been classified as trading securities in accordance with Accounting Standards Codification (“ASC”) Topics 320 and 321. Debt and equity securities reflected in long-term investments are carried at fair value. The cost of securities sold is based on the specific identification cost method. The fair value of investment securities is determined by reference to quoted market prices when available. Where quoted market prices are not available, the Companies use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Long-term investments, primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2024 and 2023 on securities still held at the balance sheet date were $872,270 and $1,725,732, respectively.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Fair Value Measurements of Assets and Liabilities—The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense—Unamortized debt expense relates to costs incurred in connection with obtaining revolving credit agreements. These costs are amortized over the term of the related revolving credit agreement and are recorded as an asset in the consolidated balance sheets. Costs incurred to issue debt are recorded as a reduction to long-term debt as presented in Note 6, Long-Term Debt.

Asset Retirement Obligations and Asset Retirement Costs—The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time of the incurrence of the obligations when such obligations are probable and the amounts can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant), for payments in satisfaction of asset retirement obligations, and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to plant closure costs, including the impacts of the coal combustion residuals rule (“CCR”), as well as obligations associated with future asbestos abatement.

Balance—January 1, 2023	$131,942,458
Accretion	12,102,012
Liabilities settled	(66,380,656)
Revisions to cash flows (1)	101,410,906
Balance—December 31, 2023	179,074,720
Accretion	9,155,891
Liabilities settled	(3,525,062)
Revisions to cash flows (1)	89,145,157
Balance—December 31, 2024	$273,850,706
Current	$ 39,992,049
Non-current	233,858,657
Balance—December 31, 2024	$273,850,706

(1) Represents non-cash investing activity.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

In response to revised regulations for coal combustion residuals and the potential for the establishment of even more reformative rules, the Companies have accelerated the timing of remediation activities related to their coal ash ponds and landfills. This resulted in liabilities settled in 2023 and 2024, as disclosed in the table above. Changes in the regulations, or in the remediation technologies could potentially result in material increases in the asset retirement obligation. The Companies will revisit the studies, as necessary throughout the process of executing remediation related to the coal ash ponds and landfills to maintain an accurate estimated cost of remediation.

The revised cash flow estimates in 2024 and 2023 reflect the outcome of the decommissioning and demolition study resulting in an upward revision of $89.1 million and $101.4 million, respectively. This increase in 2024 was driven by asbestos abatement and post closure costs.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidated financial statements herein.

Income Taxes—The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities, which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for income taxes.

Use of Estimates—The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and to disclose contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition—Revenue is recognized when the Companies transfer promised goods or services to customers in an amount that reflects the consideration to which the Companies expect to be entitled in exchange for those goods or services. Performance obligations related to the sale of electric energy are satisfied over time as system resources are made available to customers and as energy is delivered to customers and the Companies recognize revenue upon billing the customer.

The Companies have two contracts with customers that give rise to the following revenue types;

1) Sales of Electric Energy to The Department of Energy
2) Sales of Electric Energy to Sponsoring Companies

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The Companies have no contract assets or liabilities as of December 31, 2024 and 2023. The following table provides information about the Companies' receivables from contracts with customers:

	Accounts Receivable
Beginning balance—January 1, 2023	$ 50,711,358
Ending balance—December 31, 2023	65,061,157
Increase/(decrease)	$ 14,349,799
Beginning balance—January 1, 2024	$ 65,061,157
Ending balance—December 31, 2024	46,946,724
Increase/(decrease)	$ (18,114,433)

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 23, 2025, which is the date the consolidated financial statements were issued.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2024 and 2023 included the sale of all generated power, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Buckeye Power Generating, LLC, Peninsula Generation Cooperative, Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies, as well as Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2024 and 2023, balances due from the Sponsoring Companies are as follows:

	2024	2023
Accounts receivable	$ 43,515,644	$ 52,500,983

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

During 2024 and 2023, American Electric Power Company, Inc., accounted for approximately 43% of operating revenues from Sponsoring Companies and Buckeye Power Generating, LLC, accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2024. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2024	2023
General services	$ 3,125,673	$ 2,403,734
Specific projects	301,210	98,903
Total	$ 3,426,883	$ 2,502,637

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation. Charges for these services are included in the Companies' operating expense.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2025 through 2028. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 82% of their 2025 coal requirements under contract. The remaining coal requirements in 2025 will be filled by the coal supply on hand. These contracts are based on rates in effect at the time of contract execution. The Companies' total obligations under these agreements as of December 31, 2024, are included in the table below:

2025	$ 261,907,097
2026	71,676,500
2027	26,250,000
2028	26,250,000

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DCEMBER 31, 2024 AND 2023

4. ELECTRIC PLANT

Electric plant at December 31, 2024 and 2023, consists of the following:

	2024	2023
Steam production plant	$3,176,831,731	$3,085,605,811
Transmission plant	82,063,669	82,063,668
General plant	13,256,752	13,304,372
Intangible	26,564	26,564
	3,272,178,716	3,181,000,415
Less accumulated depreciation	2,270,960,768	2,145,475,614
	1,001,217,948	1,035,524,801
Construction in progress	53,739,145	17,869,041
Total electric plant	$1,054,957,093	$1,053,393,842

All property additions and replacements are fully depreciated on the date the property is placed in service unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the debt service schedule under the debt agreements, all financed projects are depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC has a revolving credit facility of $150 million which was renewed on March 16, 2023 and set to expire on March 16, 2026. At December 31, 2024 and 2023, OVEC had borrowed $145 million and $140 million, respectively, under the revolving credit facility. Additionally, OVEC has a 364-day revolving credit facility of $35 million entered into on December 19, 2023 and extended on November 9, 2024. As of December 31, 2024, OVEC had borrowed $30 million under the 364-day revolving credit facility. Interest expense related to lines of credit borrowings was $11,122,095 in 2024 and $9,022,080 in 2023. During 2024 and 2023, OVEC incurred annual commitment fees of $82,615 and $76,542, respectively, based on the borrowing limits of the line of credit.

On February 21, 2025, OVEC terminated the $35 million 364 Day Credit Agreement and amended the March 16, 2023, $150 million primary line of credit agreement. The amended agreement has a total capacity of $200 million and is set to expire on February 21, 2029.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2024 and 2023:

	Interest Rate Type	Interest Rate	2024	2023
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 44,634,587	$ 72,333,829
2006B due June 15, 2040	Fixed	6.40	46,761,205	48,429,148
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	16,221,335	29,295,163
2007A-B due February 15, 2026	Fixed	5.90	4,085,184	7,377,699
2007A-C due February 15, 2026	Fixed	5.90	4,117,713	7,436,445
2007B-A due June 15, 2040	Fixed	6.50	23,257,416	24,107,521
2007B-B due June 15, 2040	Fixed	6.50	5,857,151	6,071,242
2007B-C due June 15, 2040	Fixed	6.50	5,903,788	6,119,584
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	5,065,856	9,148,464
2008B due February 15, 2026	Fixed	6.71	9,562,814	18,138,280
2008C due February 15, 2026	Fixed	6.71	12,159,556	20,614,382
2008D due June 15, 2040	Fixed	6.91	34,199,844	35,382,998
2008E due June 15, 2040	Fixed	6.91	34,794,087	35,997,799
Series 2009 Bonds:				
2009A due February 1, 2026	Fixed	2.88	25,000,000	25,000,000
2009B due February 1, 2026	Fixed	1.38	-	25,000,000
2009C due February 1, 2026	Fixed	1.50	25,000,000	25,000,000
2009D due February 1, 2026	Fixed	2.88	25,000,000	25,000,000
Series 2010 Bonds:				
2010A due November 1, 2030	Fixed	3.00	50,000,000	50,000,000
2010B due November 1, 2030	Fixed	2.50	50,000,000	50,000,000
Series 2012 Bonds:				
2012A due November 1, 2030	Fixed	4.25	200,000,000	200,000,000
2012B due November 1, 2030	Fixed	3.00	50,000,000	50,000,000
2012C due November 1, 2030	Fixed	3.00	50,000,000	50,000,000
Series 2019 Bonds—2019A due September 1, 2019	Fixed	3.25	100,000,000	100,000,000
Total debt			821,620,536	920,452,554
Less unamortized debt expense			(5,987,838)	(7,298,473)
Total debt net of premiums, discounts, and unamortized debt expense			815,632,698	913,154,081
Current portion of long-term debt			103,407,923	98,831,592
Total long-term debt			$ 712,224,775	$ 814,322,489

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Since 2009, OVEC has entered into a number of tax-exempt financing arrangements. Under these arrangements, the Ohio Air Quality Development Authority ("OAQDA"), and the Indiana Finance

Authority ("IFA") issued tax exempt bonds, and the Companies entered back-to-back loan agreements under which the Companies are obligated to make payments equal to the principal and interest due on such bonds.

The 2009, 2010, 2012B and 2012C Bonds were originally issued as variable-rate remarketable put bonds backed by irrevocable transferable direct-pay letters of credit. These bonds were all subsequently remarketed as fixed-rate bonds with interest periods that extend through their final maturity dates, except for the 2009B and 2009C bonds, which have interest periods that extend through October 31, 2024 and November 3, 2025, respectively, at which point such bonds are subject to mandatory tender. The 2009B bond was repaid on October 31, 2024.

The 2010, 2012B, 2012C and 2019 Bonds are all scheduled to begin amortizing in 2026. The 2012A Bonds will begin amortizing in 2027.

Certain of OVEC's bonds and its revolving credit facility require the Companies to maintain a minimum of $11 million of equity, which includes common stock and retained earnings balances. Common stock and retained earnings approximated $42.6 million as of December 31, 2024.

The annual maturities of long-term debt as of December 31, 2024, are as follows:

2025	$ 103,407,923
2026	130,578,255
2027	120,092,120
2028	124,591,285
2029	129,265,197
2030–2040	213,685,756
Total	$ 821,620,536

Note that the 2025 maturities include $25 million variable-rate bonds subject to remarketing in November 2025.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2024	2023
Income tax expense at statutory rate (21%)	$ 1,818,488	$ 1,244,847
Temporary differences flowed through to customer bills	2,678,622	1,753,316
Permanent differences and other	2,890	1,837
Income tax provision	$ 4,500,000	$ 3,000,000

Components of the income tax provision were as follows:

	2024	2023
Current income tax expense—federal	$ 26,597,816	$ 16,782,327
Current income tax (benefit)/expense—state	3,639	-
Deferred income tax expense/(benefit)—federal	(22,101,455)	(13,782,327)
Total income tax provision	$ 4,500,000	$ 3,000,000

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected charges or credits in customer billings for deferred tax assets and liabilities, they have recorded a regulatory asset or liability representing income taxes billable or refundable to customers under the applicable agreements among the parties. These temporary differences will be billed or credited to the Sponsoring Companies through future billings. The regulatory asset was $55,902,459 and $33,721,522 at December 31, 2024 and 2023, respectively.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Deferred income tax assets (liabilities) at December 31, 2024 and 2023, consisted of the following:

	2024	2023
Deferred tax assets:		
Deferred revenue—advances for construction	$ 10,173,860	$ -
Pension benefits	161,111	-
Postemployment benefit obligation	1,987,714	1,849,974
Asset retirement obligations	57,245,081	37,609,157
Advanced collection of interest and debt service	25,341,728	25,380,220
Miscellaneous accruals	1,207,718	1,146,109
Other	990,179	-
Regulatory liability—postretirement benefits	29,482,207	28,815,985
Total deferred tax assets	126,589,598	94,801,445
Deferred tax liabilities:		
Prepaid expenses	(804,839)	(744,560)
Electric plant	(57,780,669)	(51,136,454)
Unrealized gain/loss on marketable securities	(216,246)	(317,346)
Postretirement benefits	(9,667,265)	(9,784,781)
Pension benefits	-	(655,532)
Regulatory asset-pension benefits	(1,153,489)	(457,571)
Regulatory asset—other	(1,917,513)	(1,272,454)
Regulatory asset—postemployment benefits	(1,987,714)	(1,849,974)
Regulatory asset—income taxes billable to customers	(11,741,045)	(7,079,145)
Total deferred tax liabilities	(85,268,780)	(73,297,817)
Valuation allowance	(63,606,792)	(43,710,106)
Deferred income tax liabilities	$ (22,285,974)	$(22,206,478)

Because future taxable income may prove to be insufficient to recover the Companies' gross deferred tax assets, the Companies have recorded a valuation allowance for deferred tax assets as of December 31, 2024 and 2023.

The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2024 and 2023, and accordingly, no liabilities for uncertain tax positions have been recognized.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2020 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2020 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2019 and earlier.

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the “Pension Plan”), covering substantially all employees hired prior to January 1, 2015. The benefits are based on years of service and each employee’s highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (“Other Postretirement Benefits”) for retired employees. Substantially all of the Companies’ employees hired prior to January 1, 2015, become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established VEBA trusts. In January 2011, the Companies established an Internal Revenue Code Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts for pension benefits and postretirement life plan represent approximately a 58% and 42% split between OVEC and IKEC, respectively, as of December 31, 2024, and a 55% and 45% split between OVEC and IKEC, respectively, as of December 31, 2023. The allocated amounts for postretirement medical plan represent approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2024, and a 53% and 47% split between OVEC and IKEC, respectively, as of December 31, 2023.

The Pension Plan’s assets as of December 31, 2024, consist of investments in equity and debt securities. All of the trust funds’ investments for the pension and postretirement benefit plans are diversified and managed in compliance with applicable laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC-IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	**Target**
Domestic equity	10 %
Fixed income	90
VEBA Plan Assets	
Domestic equity	20 %
International and global equity	20
Fixed income	60

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Fixed-Income Limitations—As of December 31, 2024, the Pension Plan fixed-income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed-income allocation is composed of a variety of fixed-income securities and mutual funds. Investment limitations for these fixed-income funds are defined by manager prospectus.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment-grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2024 and 2023, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2024	2023	2024	2023
Change in benefit obligation:				
Benefit obligation—beginning of year	$ 143,107,463	$ 175,515,791	$ 107,032,772	$ 115,228,026
Service cost	4,355,743	3,934,599	1,980,561	2,235,362
Interest cost	7,609,509	8,426,290	5,468,326	6,054,459
Plan participants' contributions	-	-	1,475,489	1,408,571
Benefits paid	(8,269,704)	(6,199,021)	(7,428,399)	(6,871,369)
Net actuarial loss (gain)	(1,756,623)	4,895,556	(158,927)	(11,022,277)
Expenses paid from assets	(217,984)	(232,062)	-	-
Settlements	-	(43,233,690)	-	-
Benefit obligation—end of year	144,828,404	143,107,463	108,369,822	107,032,772
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	140,928,756	166,305,021	153,622,675	143,795,804
Actual return on plan assets	1,595,242	17,088,508	6,704,255	15,265,390
Expenses paid from assets	(217,984)	(232,062)	-	-
Employer contributions	5,300,000	7,200,000	24,457	24,279
Plan participants' contributions	-	-	1,475,489	1,408,571
Benefits paid	(8,269,704)	(6,199,021)	(7,428,399)	(6,871,369)
Settlements	-	(43,233,690)	-	-
Fair value of plan assets—end of year	139,336,310	140,928,756	154,398,477	153,622,675
(Underfunded) overfunded status—end of year	$ (5,492,094)	$ (2,178,707)	$ 46,028,655	$ 46,589,903

See Note 1, Organization and Significant Accounting Policies, for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits.

The accumulated benefit obligation for the Pension Plan was $126,471,390 and $126,768,473 at December 31, 2024 and 2023, respectively.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

During 2023, the Pension Plan paid lump sum payouts and purchased an annuity, the total of which exceeded the Pension Plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting in the second and fourth quarters. Settlement charges of $43.2 million were recorded as of December 31, 2023. Net periodic pension benefit cost increased by $4.5 million as of December 31, 2023, as the result of the remeasurement.

Components of Net Periodic Benefit Cost—The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under GAAP, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2024	2023	2024	2023
Service cost	$ 4,355,743	$ 3,934,599	$ 1,980,561	$ 2,235,362
Interest cost	7,609,509	8,426,290	5,468,326	6,054,459
Expected return on plan assets	(10,439,557)	(10,199,408)	(9,011,255)	(8,352,410)
Amortization of prior service cost	(416,565)	(416,566)	(2,781,539)	(2,781,539)
Recognized actuarial loss (gain)	381,886	212,740	(5,595,177)	(4,163,385)
Settlement	-	4,463,353	-	-
Total benefit cost	$ 1,491,016	$ 6,421,008	$(9,939,084)	$(7,007,513)
Pension and other postretirement benefits expense recognized in the consolidated statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 5,300,000	$ 7,200,000	$ -	$ -

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2024 and 2023:

	Fair Value Measurements at Reporting Date Using			
2024	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Equity mutual funds	$ 13,254,915	$ -	$ -	$ 13,254,915
Fixed-income securities	-	90,023,267	-	90,023,267
Cash equivalents	4,381,010	-	-	4,381,010
Subtotal benefit plan assets	$ 17,635,925	$ 90,023,267	$ -	107,659,192
Investments measured at net asset value (NAV)				31,677,118
Total benefit plan assets				$ 139,336,310
2023	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 5,954,635	$ -	$ -	$ 5,954,635
Equity mutual funds	26,342,073	-	-	26,342,073
Index futures	-	81	-	81
Fixed-income securities	-	95,118,441	-	95,118,441
Cash equivalents	5,655,816	-	-	5,655,816
Subtotal benefit plan assets	$ 37,952,524	$ 95,118,522	$ -	133,071,046
Investments measured at net asset value (NAV)				7,857,710
Total benefit plan assets				$ 140,928,756

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2024 and 2023:

	Fair Value Measurements at Reporting Date Using			
	Quoted Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
2024				
Equity mutual funds	$ 42,929,235	$ -	$ -	$ 42,929,235
Equity exchange traded funds	8,575,915	-	-	8,575,915
Fixed-income mutual funds	79,765,839	-	-	79,765,839
Fixed-income securities	-	16,196,172	-	16,196,172
Cash equivalents	777,631	-	-	777,631
Benefit plan assets	$132,048,620	$16,196,172	$ -	148,244,792
Uncleared cash disbursements from benefits paid				(2,062,453)
Investments measured at net asset value (NAV)				8,216,138
Total benefit plan assets				$154,398,477
2023				
Equity mutual funds	$ 43,188,454	$ -	$ -	$ 43,188,454
Equity exchange traded funds	9,405,798	-	-	9,405,798
Fixed-income mutual funds	77,221,888	-	-	77,221,888
Fixed-income securities	-	16,963,326	-	16,963,326
Cash equivalents	505,281	-	-	505,281
Benefit plan assets	$130,321,421	$16,963,326	$ -	147,284,747
Uncleared cash disbursements from benefits paid				(1,638,519)
Investments measured at net asset value (NAV)				7,976,447
Total benefit plan assets				$153,622,675

Investments that were measured at net asset value per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder upon no more than 30 days' notice. The values reported above are based on information provided by the fund manager.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2024 and 2023, were as follows:

	Pension Plan		Other Postretirement Benefits			
			2024		2023	
	2024	2023	Medical	Life	Medical	Life
Discount rate	5.72 %	5.35 %	5.72 %	5.72 %	5.35 %	5.35 %
Rate of compensation increase for next year	5.00	4.00	N/A	5.00	N/A	4.00
Rate to which compensation is assumed to decline (ultimate trend rate)	3.00	3.00	N/A	3.00	N/A	3.00
Year that rate reaches the ultimate trend	2027	2026	N/A	2027	N/A	2026

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2024 and 2023, were as follows:

	Pension Plan		
	For the Period January 1 through December 31, 2024	For the Period July 1 through December 31, 2023	For the Period January 1 through June 30, 2023
Discount rate	5.35 %	5.44 %	5.61 %
Expected long-term return on plan assets	7.50	7.00	7.00
	2024		**2023**
Rate of compensation increase for next year	4.00 %		4.50 %
Rate to which compensation is assumed to decline (ultimate trend rate)	3.50		4.00
Ultimate compensation rate	3.00		3.00
Year that rate reaches the ultimate trend	2026		2026

	Other Postretirement Obligations			
	2024		2023	
	Medical	Life	Medical	Life
Discount rate	5.35 %	5.35 %	5.57 %	5.57 %
Expected long-term return on plan assets	5.88	6.50	5.83	6.50
Rate of compensation increase	N/A	4.00	N/A	4.50

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Assumed health care cost trend rates at December 31, 2024 and 2023, were as follows:

	2024	2023
Health care trend rate assumed for next year—participants under 65	6.50 %	6.75 %
Health care trend rate assumed for next year—participants over 65	6.50	6.75
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2029	2029

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2024 and 2023, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2024	2023	2024	2023
Asset category:				
Equity securities	32 %	29 %	38 %	39 %
Debt securities	68	71	62	61

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $6.3 million to their Pension Plan and $25.1 thousand to their Other Postretirement Benefits plan in 2025.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2025	$ 7,518,680	$ 7,541,908
2026	7,772,929	7,966,554
2027	8,105,351	8,313,283
2028	8,482,804	8,585,852
2029	8,908,545	8,808,805
Five years thereafter	51,671,163	48,550,078

Postemployment Benefits—The Companies follow the accounting guidance in ASC Topic 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 29% and 71% split between OVEC and IKEC, respectively, as of

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

December 31, 2024, and approximately a 34% and 66% split between OVEC and IKEC, respectively, as of December 31, 2023. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $9,464,083 and $8,808,588 at December 31, 2024 and 2023, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' pay contributed. In addition, the Companies provide contributions to eligible employees hired on or after January 1, 2015, of 3% to 5% of pay based on age and service. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2024 and 2023 were $2,305,433 and $2,001,057, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations—In response to Air Regulations adopted by the USEPA to meet ambient air quality standards, the Companies determined that it would be necessary to install flue gas desulfurization ("FGD") systems at both plants. Following completion of the necessary engineering and permitting, construction initiated and the two Kyger Creek FGD systems were placed into service in 2011 and 2012, while the two Clifty Creek FGD systems were placed into service in 2013.

These FGD systems remain in service, and continue to perform in compliance with all applicable regulations and permit conditions. In addition, the USEPA also adopted the Mercury and Air Toxics Standards ("MATS") rule that established emission limits and went into effect April 16, 2015. The USEPA also promulgated an updated MATS rule in May of 2024. That rule is undergoing litigation; however, the Companies are maintaining compliance with the existing MATS rules and expect the installed pollution control systems at each plant will be adequate to meet the stringent emissions requirements outlined in the new MATS rule if it is ultimately upheld.

Since 2017, the companies have also been subject to stringent ozone season NOx emissions requirements under the Cross State Air Pollution Rules ("CASPR") promulgated pursuant to requirements under the Clean Air Act. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update requirements in the 2017 ozone season and that strategy was standardized to meet future ozone season compliance obligations. To date, that strategy has resulted in successful ozone season compliance through 2024. The CSAPR regulations have also been updated by the USEPA, and the latest revisions that became effective in March of 2023 (referred to as the "Good Neighbor Rule") have also been subject to extensive litigation and that rule is subject to a stay issued by the United States Supreme Court until the legal challenges are resolved.

In the interim, the historic CASPR regulations remain in effect, and that rule is not expected to materially impact the Companies near term compliance strategy for the ten units with selective catalytic reduction controls for NOx emissions.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO2 allowances available every year without having to rely on market purchases to comply with applicable rules. Given the success of the Companies' NOx ozone season compliance strategy, the purchase of additional NOx allowances has not been needed for the past several years; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons. Should the more stringent NOx regulations promulgated by the USEPA in 2023 ultimately withstand the legal challenges, that rule could result in additional restrictions on Unit 6 during the ozone season.

In 2024, the Ohio EPA adopted a new State Implementation Plan ("SIP") for compliance with the Regional Haze Program authorized under the Clean Air Act. The SIP is currently being reviewed by the USEPA, and it establishes new emissions limits for several coal-fired generating stations within Ohio, including a new year-round NOx emissions limit for the Kyger Creek Station. This new limit can be achieved with the current NOx emission controls and it is not expected to materially impact unit operations.

CCR Rule—The USEPA's CCR Rule became effective in October 2015 to regulate CCR as a nonhazardous solid waste. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule is self-implementing and currently does not require state action for the states of Indiana or Ohio. As a result of this self-implementing feature, the rule contains extensive recordkeeping and notice requirements, including requirements for disclosing CCR compliance information on the Companies' publicly available website.

The Companies have been systematically implementing the applicable provisions of the CCR Rule and all revisions thereof. The Companies have completed all compliance obligations to date.

Since the initial publication of the CCR rules in 2015, several legal, legislative, and regulatory events impacting the scope, applicability, and future CCR compliance obligations and timelines have also taken place. Final actions include: 1.) federal legislation (i.e., the Water Infrastructure Improvements for the Nation Act("WIIN")) that provides a pathway for states to seek approval for administering and enforcing the federal CCR program; 2.) The USEPA's issuance of a Phase I, Part I revision to the CCR rules on March 1, 2018; 3.) the D.C. Circuit Court's August 21, 2018, ruling, vacating and remanding portions of the CCR rule, and 4.) The USEPA's issuance of a final CCR Rule, Part A, which was published in the *Federal Register* on August 28, 2020. This final rule introduced a significant revision to the 2015 CCR rule requiring all impoundments that do not meet the liner requirements outlined in the rule to cease receiving CCR material and initiate closure could have been by April 11, 2021, regardless of their overall compliance status. If that date was determined to not be technically feasible, an alternate date to cease receiving CCR material and initiate closure could have been secured from the USEPA through a proposed extension request process, which was required to be submitted to the USEPA no later than November 30, 2020. The surface impoundments at Kyger Creek and Clifty Creek were not constructed in a manner that meets the definition of a liner under the 2015 CCR rule. As a result, the Companies completed an engineering evaluation to develop preliminary closure designs for the impoundments, to determine a technically feasible timeline for discontinuing placement of CCR and non-CCR waste streams in these impoundments, and to initiate closure of the CCR impoundments consistent with the requirements of the rule. The Companies submitted technical justification documents to the USEPA in compliance with the November 30, 2020, deadline that demonstrated why additional time was needed to cease placement of CCR and non-CCR waste streams in the surface impoundments and initiate closure. Separately, the proposed Part B revisions to the 2015 CCR rule outline the development of a federal permitting program to regulate and enforce the CCR rule at all applicable facilities consistent with the Congressional mandate outlined in the WIIN Act. This federal permit program would replace the current enforcement mechanism of a self-implementing rule enforced through citizen suits and place it back with the USEPA or any state regulator that receives primacy to implement the CCR permitting within their respective state. The Companies are actively monitoring these developments and adapting their CCR compliance program to ensure compliance obligations and timelines are adjusted accordingly.

The Companies secured various environmental permits in support of the CCR compliance strategy developed to comply with the CCR Rule, Part A and initiated work in 2021. On January 11, 2022, the IKEC Clifty Creek Station received a preliminary determination from USEPA proposing to deny the alternative closure deadlines IKEC requested for its two surface impoundments in the demonstration application filed by IKEC on November 30, 2020. However, the USEPA took no final action on the proposed denial of the Clifty Creek Station's application. The Kyger Creek Station filed a similar demonstration application in November of 2020. The Companies did not receive final determinations from the USEPA for either the Clifty Creek or Kyger Creek Stations. The Companies executed their compliance strategy and maintained compliance with the CCR Rule by completing the work and ceasing receipt of CCR and non-CCR waste streams prior to October 15, 2023.

On May 9, 2024, the USEPA finalized the Legacy CCR rule, which became effective November 8, 2024. The Legacy Rule establishes requirements for legacy impoundments, coal combustion residuals management units ("CCRMUs"), as well as provides clarification on various CCR regulatory definitions. Based on OVEC's review of the Legacy Rule, the Companies are not subjected to the legacy impoundment conditions, but will need to comply with CCRMU requirements. The first compliance obligation associated with the Legacy Rule for the Companies is February 6, 2026. Separately, the Legacy Rule was challenged by the industry for various reasons and is undergoing litigation. On February 13, 2025, the USEPA filed a motion requesting abeyance of litigation for 120 days to allow transition to the new administration. The D.C. Circuit Court granted the request for abeyance and directed the USEPA to file a motion to govern further proceedings by June 13, 2025. Until litigation is exhausted, the Companies cannot assess the full impacts of the rule at this time.

Changes in regulations or in the Companies' strategies for mitigating the impact of coal combustion residuals could potentially result in material increases to the asset retirement obligations. The

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Companies will revisit the demolition and decommissioning studies as appropriate throughout the process of executing closure of the CCR surface impoundments to maintain an appropriate estimated cost of ultimate facility closure and decommissioning.

NAAQS Compliance for SO2—On June 22, 2010, the USEPA revised the Clean Air Act by developing and publishing a new one-hour SO2 NAAQS of 75 parts per billion, which became effective on August 23, 2010. States with areas failing to meet the standard were required to develop state implemented plans to expeditiously attain and maintain the standard.

On August 15, 2013, the USEPA published its initial non-attainment area designations for the new one-hour SO2, which did not include the areas around Kyger Creek or Clifty Creek. However, the amended rule does establish that at a minimum, sources that emit 2,000 tons of SO2 or more per year be characterized by their respective states using either modeling of actual source emissions or through appropriately sited ambient air quality monitors.

In addition, the USEPA entered into a settlement agreement with Sierra Club/Natural Resources Defense Council in the U.S. District Court for the Northern District of California requiring the USEPA to take certain actions, including completing area designation by July 2, 2016, for areas with either monitored violations based on 2013-15 air quality monitoring or sources not announced for retirement that emitted more than 16,000 tons SO2 or more than 2,600 tons with a 0.45 SO2/mmBtu emission rate in 2012.

Both Kyger Creek and Clifty Creek directly or indirectly triggered one of the criteria and have been evaluated by the respective state regulatory agencies through modeling. The modeling results showed Clifty Creek could meet the new one-hour SO2 limit using their current scrubber systems without any additional investment or modifications. Kyger Creek's modeling data was rejected by USEPA as inconclusive in 2016. As a result, the USEPA required Kyger Creek to install an SO2 monitoring network around the plant and monitor ambient air quality beginning on January 1, 2017. Based on the first three years of data from that network, the Ohio Environmental Protection Agency prepared an updated petition to the USEPA in early 2020 requesting that the area in the county surrounding the plant be re-designated to attainment/unclassifiable with the one-hour SO2 standard. The USEPA subsequently acted on this request and published a notice in the *Federal Register* proposing to make this re-designation. A final rulemaking approving the re-designation was expected in 2021; however, the USEPA failed to act on the re-designation. While a final decision has not been rendered as of December 31, 2024, the Company remains optimistic that the USEPA will render a decision as there is now six years of data supporting a re-designation determination. On February 26, 2019, the USEPA issued a final decision that it is retaining the existing primary SO2 NAAQS at 75 parts per billion for the next five-year NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid more restrictive permit limits relative to its SO2 emissions or the need for additional capital investment in major scrubber upgrades or modifications.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

NAAQS Compliance for Particulate Matter ("PM")—In 2021, the Biden administration signaled via Executive Order that it intended to revisit the 2020 PM NAAQS standard and lower it. On January 6, 2023, USEPA announced its proposed decision to revise the primary health-based annual PM2.5 standard from its current level of 12.0 µg/m3 to within the range of 9.0 to 10.0 µg/m3. On March 6, 2024, the USEPA published a final rule revising and lowering the prior PM NAAQS to 9.0 µg/m3. The Rule became effective on May 6, 2024, and states were expected to begin a multi-year process to determine if there are areas not meeting the new standard and, if so, develop State Implementation Plans ("SIP") to address those non-attainment areas. Under the Rule, each SIP will also need to be submitted to the USEPA for review and approval, which could result in additional SO2 and/or NOx emissions reductions for the utility sector. However, industry groups and states, including Ohio and Indiana, challenged the Rule in D.C. Circuit Court. As of the date of this report, no decision has been reached and, at the request of the USEPA, challenges to the Rule are being held in abeyance until April 28, 2025, while the new administration reviews the Rule. Additionally, on March 12, 2025, the USEPA announced its intent to reconsider the PM NAAQS standards to support President Trump's Executive Order, "Unleashing American Energy" issued on January 20, 2025.

The companies will continue to monitor the activities that the USEPA and the states undertake associated with the new PM NAAQS to determine what impact revisions to this NAAQS standard could have on unit operations.

Steam Electric Effluent Limitations Guidelines—On September 30, 2015, the USEPA signed a new final rule governing Effluent Limitations Guidelines ("ELGs") for the wastewater discharges from steam electric power generating plants. The rule, which was formally published in the *Federal Register* on November 3, 2015, impacted future wastewater discharges from both the Kyger Creek and Clifty Creek stations.

The rule was intended to require power plants to modify the way they handle a number of wastewater processes. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the USEPA issued an administrative stay on the ELG rule In June 2017, the USEPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The USEPA revised the rule redefining what constitutes "best available technology" for these two wastewater discharges and issued an updated final rule in the *Federal Register* on October 13, 2020.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Based on the original rule and revisions captured in the 2020 update, the following impacts to each wastewater discharge are expected:

1. Kyger Creek was required to convert to dry fly ash handling by no later than December 31, 2023. Construction activities associated with dry fly ash conversion at Kyger Creek were completed in late 2022. The Clifty Creek Station was not impacted since the conversion to dry fly ash was completed prior to the implementation of this rule.

2. The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. As a result, Clifty Creek and Kyger Creek were converted to a closed-loop bottom ash management system for boiler slag, with up to a 10% purge based on each facility’s total wetted volume. Each system was placed into service in advance of October 15, 2023.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges for arsenic, mercury, selenium, and nitrate/nitrite nitrogen. After reviewing the requirements of the 2015 edition of the rule, the Companies expected both Clifty Creek and Kyger Creek Stations to be able to meet the mercury and arsenic limitations with the current wastewater treatment technology; however, the Companies anticipated the potential need to add some form of biological, or equivalent nonbiological, treatment system downstream of each station’s existing FGD wastewater treatment plant to meet the new nitrate/nitrite nitrogen and selenium limitations. Installation of new controls to meet the final effluent limitations contained in the revised rule was placed on hold while the USEPA reconsidered the 2015 ELG rule to ensure that the compliance strategy ultimately selected would be able to meet any revised requirements in the updated ELG rule. With the finalization of the October 13, 2020 ELG Revision, the Companies resumed evaluation of the appropriate technology, design, and schedule to achieve compliance with the new requirements, which included a change in the final effluent limitations for arsenic, nitrate/nitrite, mercury and selenium. The Companies worked with outside engineering resources, developed preliminary design reports, and conducted a pilot test at the Kyger Creek station in 2021. Further, the Companies worked with state agencies to request the revised ELG applicability date for FGD wastewater of no later than December 31, 2025. This compliance date is now incorporated into both plant’s National Pollutant Discharge Elimination System (“NPDES”) permits. Construction activities associated with the installation of bioreactors at both plants will commence late in the second quarter of 2025.

The 2024 ELG Rule was published in the *Federal Register* on May 9, 2024, and became effective on July 8, 2024. The updated ELG rule placed additional requirements on FGD wastewater, bottom ash transport water, combustion residuals leachate and unmanaged combustion residuals leachate. Facilities subject to the rule are required to either invest in additional technologies to meet the obligations of the rule, or elect to submit a Notice of Planned Participation by December 31, 2025, to cease coal combustion by December 31, 2034. The industry challenged the updated ELG Rule through a series of legal actions. Most recently, the litigation rule was placed in abeyance by the Eighth Circuit of Court for a period of 60 days to provide the USEPA time to reevaluate the rule consistent with the new administration’s focus on energy.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The Companies will continue to monitor USEPA regulatory actions on this pending rule and will continue to execute their compliance plan in 2025.

316(b) Compliance—The 316(b) rule was published as a final rule in the *Federal Register* on August 15, 2014, and impacts facilities that use cooling water intake structures designed to withdraw at least 2 million gallons per day from waters of the U.S., and those facilities who also have an NPDES permit. The rule requires such facilities to choose one of seven options specified by the rule to reduce impingement to fish and other aquatic organisms. Additionally, facilities that withdraw 125 million gallons or more per day must conduct entrainment studies to assist state permitting authorities in determining what site-specific controls are required to reduce the number of aquatic organisms entrained by each respective cooling water system.

The Companies have completed the required two-year fish entrainment studies and filed the reports with the respective state regulatory agencies consistent with regulatory requirements under 40 CFR Section 122.21(r).

The timeline for retrofits to the Kyger Creek Station's cooling water intake structure has been incorporated into its NPDES permit, with installation of the first sets of modified traveling water screens completed in 2024. Subsequent sets of modified traveling water screens will be installed consistent with the requirements of the facility's NPDES permit. Negotiation associated with the retrofits for the Clifty Creek Station are still underway with the Indiana Department of Environmental Management and will be incorporated into the facility's NPDES permit upon settlement. The Companies anticipate receiving a modified NPDES permits in the second quarter of 2025, and commencing installation of the first sets of modified traveling water screens in the fall of 2025.

Utility Sector Greenhouse Gas Regulations—The USEPA has proposed regulations under Section 111(b) and (d) of the Clean Air Act to establish requirements for existing coal-fired and new natural gas fired steam electric generators. The proposed rules applicable to existing coal-fired steam electric generators larger than 100 MW in size may require those units to ultimately retire, co-fire with natural gas, and/or install carbon capture and sequestration technology to maintain long-term operations. The regulation was published with the Federal Register on May 9, 2024. The rule was challenged by the utility industry and a number of state agencies, with the litigation ultimately being heard in the D.C. Circuit Court, who has yet to rule on the case at the date of this report. Most recently, litigation and rule were placed in abeyance by the D.C. Circuit Court for a period of 60 days, beginning February 19, 2025, to provide the USEPA time to reevaluate the rule consistent with the new administration's focus on energy.

The Companies will continue to monitor USEPA regulatory actions and will respond as necessary. Environmental rules and regulations discussed throughout the Environmental Matters footnote could require material additional capital expenditures or maintenance expenses in future periods.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for financial instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed-income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings as they are actively traded at quoted market prices. Certain fixed-income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed-income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed-income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

As of December 31, 2024 and 2023, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments, including money market mutual funds, equity mutual funds, and fixed-income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short-term in nature, their carrying amounts approximate fair value.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Long-Term Investments—Assets measured at fair value on a recurring basis at December 31, 2024 and 2023, were as follows:

	Fair Value Measurements at Reporting Date Using		
	Quoted Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2024			
Fixed-income securities	$ -	$ 149,541,547	$ -
Cash equivalents	20,183,022	-	-
Total fair value	$ 20,183,022	$ 149,541,547	$ -
Assets not subject to fair value levels:			
Money Market Demand Deposit Account			$ 47,251,335
Total long-term investments			$ 216,975,904
2023			
Fixed-income securities	$ -	$ 118,360,679	$ -
Cash equivalents	27,877,237	-	-
Total fair value	$ 27,877,237	$ 118,360,679	$ -
Assets not subject to fair value levels:			
Money Market Demand Deposit Account			$ 45,135,443
Total long-term investments			$ 191,373,359

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2024 and 2023, are as follows:

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

	2024		2023	
	Fair Value	Recorded Value	Fair Value	Recorded Value
Total	$ 834,706,963	$ 821,620,536	$ 929,279,387	$ 920,452,554

11. LEASES

OVEC has various operating leases for the use of other property and equipment. On January 1, 2019, the Companies adopted ASC 842, *Leases* which, among other changes, requires the Companies to record liabilities classified as operating leases on the balance sheet along with a corresponding right-of-use asset. The Companies elected the package of practical expedients available for expired or existing contracts, which allowed them to carryforward their historical assessments of whether contracts are or contain leases, lease classification tests and treatment of initial direct costs. Further, the Companies elected to not separate lease components from non-lease components for all fixed payments and excluded variable lease payments in the measurement of right-of-use assets and lease obligations.

The Companies determine whether an arrangement is, or includes, a lease at contract inception. Leases with an initial term of 12 months or less are not recognized on the balance sheet. The Companies recognize lease expense for these leases on a straight-line basis over the lease term.

Operating lease right-of-use assets and liabilities are recognized at commencement date and initially measured based on the present value of lease payments over the defined lease term. Operating leases are immaterial as of December 31, 2024.

Contracts determined to be leases typically do not provide an implicit rate; therefore, the Companies use the estimated incremental borrowing rate at the time of lease commencement to discount the present value of lease payments. In order to apply the incremental borrowing rate, a portfolio approach with a collateralized rate is utilized. Assets were grouped based on similar lease terms and economic environments in a manner whereby the Companies reasonably expect that the application is not expected to differ materially from a lease-by-lease approach.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

The Companies have finance leases for the use of vehicles, property, and equipment. The leases have remaining terms of 0 to 4 years. The components of lease expense are as follows:

	December 31, 2024
Finance lease cost:	
Amortization of leased assets	$ 998,852
Interest on lease liabilities	117,315
Total finance lease cost	$ 1,116,167

Supplemental cash flow information related to leases was as follows:

Financing cash flows from finance leases	$ 998,852
Weighted average remaining lease term:	
Finance leases	2
Weighted average discount rate:	
Finance leases	5.09 %

The amount in property under finance leases is $5,555,438 and $5,217,996 with accumulated depreciation of $3,529,466 and $2,674,161 as of December 31, 2024 and 2023, respectively.

Future maturities of finance lease liabilities are as follows:

Years Ending December 31	Finance
2025	$ 1,044,124
2026	446,103
2027	310,457
2028	154,636
2029	46,353
Total future minimum lease payments	2,001,673
Less estimated interest element	166,634
Estimated present value of future minimum lease payments	$ 1,835,039

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by litigation, claims and uncertainties that arise in the ordinary course of business. The Companies regularly analyze current information and, as necessary provide accruals for probable and reasonably estimable liabilities on the eventual disposition of these matters. Management believes that the ultimate outcome of these matters will not have a significant, adverse effect on either the Companies' future results of operation or financial position.

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of Ohio Valley Electric Corporation:

Opinion

We have audited the consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2024 and 2023, and the related consolidated statements of income and retained earnings and cash flows for the years then ended, and the related notes to the consolidated financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Companies as of December 31, 2024 and 2023, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Companies and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Companies' ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Companies' ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Deloitte & Touche LLP

April 23, 2025

OVEC PERFORMANCE - A 5-YEAR COMPARISON

Power Generation & Delivery

	2024	2023	2022	2021	2020
Net Generation (MWh)	9,989,291	9,576,348	11,014,053	10,071,966	9,025,018
Energy Delivered (MWh) to Sponsors	9,987,634	9,581,490	11,047,708	10,063,687	9,033,056
Maximum Scheduled (MW) by Sponsors	2,166	2,057	2,161	2,227	2,215
Fuel Consumed (in thousands)	$373,259	$344,622	$354,336	$260,174	$231,316
Total Power Cost to Sponsors (in thousands)	$838,104	$744,247	$764,592	$662,365	$605,270
Average Price (MWh) Sponsors	$83.91	$80.81	$69.21	$65.82	$67.01

Financial (in thousands)

	2024	2023	2022	2021	2020
Operating Revenues	$794,172	$855,002	$761,499	$623,425	$551,718
Operating Expenses	$740,464	$800,164	$703,020	$559,559	$480,383
Operating Income	$53,708	$54,838	$58,479	$63,866	$71,335
Other Income (Expense)	$972	$198	($28)	($28)	$87
Interest Charges	$50,521	$52,107	$55,750	$61,141	$68,611
Net Income	$4,159	$2,929	$2,701	$2,697	$2,810
Electric Utility Plant, net	$1,054,957	$1,053,394	$1,151,646	$1,181,916	$1,239,491
Total Assets	$1,749,514	$1,682,055	$1,721,554	$1,732,720	$1,790,606
Total Long-Term Debt (including current portion)	$815,633	$913,154	$981,295	$1,112,132	$1,204,816
Retained Earnings	$32,589	$28,430	$25,502	$22,801	$20,104

Performance

	2024	2023	2022	2021	2020
Power Use Factor (percent)	74.5	69.1	90.5	76.6	60.8
Commercial Availability (percent)	89.2	84.8	79.6	85.3	91.6
Equivalent Forced Outage Rate (percent)	6.8	5.6	11.0	6.6	4.4
Heat Rate (Btu per kWh, net generation)	10,868	10,845	10,626	10,733	11,036

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

DIRECTORS

Ohio Valley Electric Corporation

[1] **THOMAS ALBAN**, Columbus, Ohio
Vice President, Power Generation
Buckeye Power, Inc.

ERIC D. BAKER, Cadillac, Michigan
President and Chief Executive Officer
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INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
DATA REQUEST SET NO. AG-SC-CUB SET 1
CASE NO. U-21428

DATA REQUEST NO. AGSCCUB 1-12

Request

Provide the ICAP for I&M’s share of OVEC in 2024.

Response

The Company's Power Participation Ratio share of OVEC provided 166 MW of Installed Capacity (ICAP) for both the PJM Planning Year spanning from June 1, 2023 - May 31, 2024 and June 1, 2024 - May 31, 2025.

Preparer:

Jason M. Stega

Capacity Markets

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price without having to build capacity or purchase capacity bilaterally from incumbent generation owners at monopoly prices. The first, the daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. In order for the PJM markets to be self sustaining, the net revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market.

PJM's introduction of its significantly modified ELCC method in the 2025/2026 BRA was another radical change to the capacity market design. While it is a good idea to evaluate unit specific performance and a good idea to recognize that risk occurs in the winter as well as the summer and that risks are correlated, ELCC was implemented before it could be fully tested and unintended consequences evaluated. The results of the 2025/2026 BRA illustrate the extreme sensitivity of the market outcomes to a range of assumptions and decisions about market design details that were not adequately tested or reviewed with stakeholders.[1]

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources are required to offer into the capacity auctions. The current exception of intermittent and storage capacity from the must offer requirement is inconsistent with the PJM market design and the significance of this exception is growing.[2] All LSEs must buy capacity equal to their peak load plus a reserve margin.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and offer them into the capacity market, or

1 The MMU prepared a series of reports on the 2025/2026 BRA results which can be found here: <https://www.monitoringanalytics.com/reports/Reports/2024.shtml> and here <https://www.monitoringanalytics.com/reports/Reports/2025.shtml>

2 FERC approved extending the must offer requirement to intermittent resources but not to demand response resources on February 20, 2025. 190 FERC ¶ 61,117.

construct transmission upgrades and offer them into the capacity market.

There are significant market design issues in the PJM Capacity Market that currently prevent the market from achieving competitive results.

The Market Monitoring Unit (MMU) analyzed market design, market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[3] The conclusions are a result of the MMU's evaluation of the 2025/2026 Base Residual Auction.[4] [5] [6] [7] [8] [9]

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]
- Participant behavior was evaluated as not competitive in the 2025/2026 BRA. The offers of most market sellers were competitive after the Commission order corrected the definition of the market seller offer cap.[12] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. However, a significant level of categorically exempt resources did not offer and the result was to increase the clearing prices above the competitive level.
- Market performance was evaluated as not competitive based on the 2025/2026 Base Residual Auction as a result of the failure to offer of categorically exempt resources, the flaws in the Effective Load Carrying Capability (ELCC) design including the failure to correctly define the reliability contribution of thermal resources in the winter and the failure to include reliability must run (RMR) capacity in the supply curve.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design, there are several features of the RPM design which still threaten competitive outcomes. These include the details of PJM's ELCC implementation, the failure to apply the RPM must offer requirement consistently, the inclusion of performance assessment interval (PAI) penalties, the exclusion of RMR resources from supply, the use of gross CONE as the maximum price on the VRR curve, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.

3 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

4 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.

5 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.

6 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (November 6, 2025) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>.

7 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>.

8 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (January 31, 2025). <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf>.

9 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (February 4, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf>

10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.

11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

12 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023). The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[13] PJM introduced the Capacity Performance design for the 2017/2018 BRA. PJM introduced a new ELCC method for defining capacity MW offered in the 2025/2026 BRA.[14]

Under RPM, capacity obligations are annual.[15] By design, Base Residual Auctions (BRA) are held for delivery years that are three years in the future despite recent auction delays. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[16] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year although some incremental auctions have not been held as a result of delays in holding BRAs.[17] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[18] A Reliability Backstop Auction may be conducted if tariff defined criteria are met to resolve reliability criteria violations caused by lack of sufficient capacity procured through RPM auctions.[19] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percent lower than the approved PJM installed reserve margin, PJM will make a filing with FERC to conduct a Reliability Backstop Auction. If the total UCAP committed for all base load generation resources in BRAs for three consecutive years is less than the forecasted minimum hourly load, PJM will make a filing with FERC to conduct a Reliability Backstop Auction.

The 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction were conducted in 2024. Based on the FERC Order in Docket No. ER23-729-002, PJM reran the 2024/2025 RPM Base Residual Auction with final results posted on May 6, 2024, and PJM reran the 2024/2025 Third Incremental Auction with final results posted on May 23, 2024.[20] [21] [22] The 2025/2026 RPM Base Residual Auction was conducted in July 2024.

Market Structure

- **RPM Installed Capacity.** In 2024, RPM installed capacity increased 1,281.2 MW or 0.7 percent, from 178,375.0 MW on January 1, to 179,656.2 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2025/2026 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 14,319.1 MW, or 71.1 percent of required reserves and 68.1 percent of total reserves. The fact that more than two thirds (68.1 percent) of the PJM reserves depend on resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2024, 49.4 percent was gas; 21.0 percent was coal; 17.9 percent was nuclear; 4.3 percent was hydroelectric; 2.2 percent was oil; 2.0 percent was wind; 0.3 percent was solid waste; and 2.8 percent was solar.
- **Market Concentration.** In the 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[23] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market

13 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
14 See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).
15 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
16 See 126 FERC ¶ 61,275 at P 86 (2009).
17 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
18 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
19 See OATT Attachment DD § 16.
20 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.
21 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
22 187 FERC ¶ 61,065 (2024).
23 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[24] [25] [26]

- **Imports and Exports.** Of the 1,268.5 MW of imports offered in the 2025/2026 RPM Base Residual Auction, 1,268.5 MW cleared. Of the cleared imports, 700.5 MW (55.2 percent) were from MISO.
- **Demand Resources.** Committed DR was 7,699.9 MW for June 1, 2024, as a result of cleared capacity for demand resources in RPM auctions for the 2024/2025 Delivery Year (8,064.7 MW) less replacement capacity (364.8 MW).
- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy. Committed EE was 7,668.0 MW for June 1, 2024, as a result of MW offered at a price less than or equal to the RPM auction clearing price in RPM auctions for the 2024/2025 Delivery Year (7,716.0 MW) less replacement MW (48.0 MW).

Market Conduct

- **2024/2025 RPM Third Incremental Auction.** Of the 320 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for seven generation resources (2.2 percent).
- **2025/2026 RPM Base Residual Auction.** Of the 1,119 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 61 generation resources (5.5 percent).

Market Performance

- The 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction were conducted in 2024. The weighted average capacity price for the 2023/2024 Delivery Year is $42.01 per MW-day, including all RPM auctions for the 2023/2024 Delivery Year. The weighted average capacity price for the 2024/2025 Delivery Year is $45.57 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year.
- For the 2024/2025 Delivery Year, RPM annual charges to load are $2.5 billion.
- In the 2025/2026 RPM Base Residual Auction, the market performance was determined to be not competitive.

Part V Reliability Service (RMR)

- Of the nine companies (28 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other seven companies (21 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in 2024 was 5.2 percent, a decrease from 5.5 percent in 2023.[27]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2024 was 83.2 percent, an increase from 83.1 percent in 2023.

Recommendations[28]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources,

24 See OATT Attachment DD § 6.5.
25 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
26 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
27 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on January 22, 2025. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.
28 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

and imports.[29] [30] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 delivery year. EE is not a capacity resource as defined in the tariff, and there is no reason to continue to pay large subsidies to EE providers.[31] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[32]
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources at or below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined ELCC derating factors are lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Adopted 2023.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs to intermittent resources that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[33]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times Net CONE, capped at Gross CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. First reported Q3 2024. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of

29 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
30 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
31 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 37 (Dec. 18, 2024).
32 See 189 FERC ¶ 61,095 (2024).
33 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

all at risk units should be included in the redefined model including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[34]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[35]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer

34 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

35 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)

- The MMU recommends that modifications to existing resources, including relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[36]
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[37]
- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)

36 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

37 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[38] (Priority: High. First reported 2013. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage and associated performance penalty. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance.

38 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

(Priority: High. First reported 2019. Status: Not adopted.)

- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-29) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by

the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Conclusion

The analysis of the PJM Capacity Market begins with market design and market structure, which provide the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market design and market structure. Regardless of the ownership structure of a market, the market design can result in noncompetitive outcomes. In a good market design and a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. The analysis also examines the impact of market design choices on market performance.

The MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including by the CP design, by PJM's ELCC approach, by the definition of the maximum VRR price as gross CONE, by the failure to extend the RPM must offer requirement to all resources, including, in some cases, the exercise of market power through the withholding of categorically exempt resources, by the product definition and lack of market power mitigation for demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC market design and do also reflect, in part, the tightening of supply and demand conditions in the PJM Capacity Market.[39]

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless, a competitive outcome can be assured by appropriate market power mitigation rules within an effective market design. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules.

The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The maximum price on the VRR curve has a significant impact on market prices particularly when the market is tight. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The VRR curves used in the 2025/2026 BRA included a maximum price equal to gross CONE for most LDAs that resulted in a significant increase in customer payments for load as a result of paying a price above the competitive level. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power.

For the 2025/2026 RPM Base Residual Auction, the level of committed demand resources (6,085.6 MW UCAP) exceeds the entire level of excess capacity (870.9 MW). This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in 2025/2026 will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in 2025/2026 will experience the implications of the definition of demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves. Nonetheless, as another significant flaw in the market design, PJM does not include DR in its definition of

39 PJM's ELCC filing that created many of these issues was approved by FERC. 186 FERC ¶ 61,080 (January 30, 2024).

primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market.

There are currently two important gaps in the market power rules for the PJM Capacity Market. The RPM must offer requirement is not applied uniformly to all capacity resources. There are no market power mitigation rules that apply to demand resources.

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and Dominion RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[40] [41]

The correct definition of a competitive offer in the capacity market is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with mitigating rational capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the PAI penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates an artificial rationale for not having a must offer obligation for intermittent and storage resources, creates complexity in the calculation of CPQR and increases CPQR above rational levels, and ultimately raises the price of capacity above the competitive level.

Rather than penalizing capacity resources at extremely high levels for nonperformance only during PAI events, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI events. CP has not worked as the theory suggested. PAI events are high impact low probability events. The failure of the PAI incentives to prevent a very high level of outages during Winter Storm Elliott illustrates the weakness of incentives based on this type of event. In addition, the actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is (B) * (ELCC accredited UCAP factor for a unit), where B is the balancing ratio and the ELCC accredited UCAP factor is the derating factor. For example, if B were 80 percent, the actual required performance for a unit with an 80 percent ELCC accredited UCAP factor would be only 64 percent of ICAP (.80 * .80). For units with low ELCC accredited UCAP factors, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

40 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

41 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[42] [43] [44] [45] [46] [47] [48] [49] [50] [51] [52] In 2024, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. A majority of capacity investments in PJM were financed by market sources. Of the 55,064.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2023/2024 Delivery Years, 42,444.9 MW (77.1 percent) were based on market funding. Of the 8,966.4 MW of additional capacity that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Year, 5,532.6 MW (61.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

42 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
43 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
44 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
45 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
46 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).
47 See "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
48 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
49 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
50 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
51 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf> (September 20, 2024).
52 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf> (October 15, 2024).

Table 5-2 RPM related MMU reports: 2024

Date	Name
January 12, 2024	IMM Answer to PJM Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_ER24-99_20240112.pdf
January 14, 2024	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_-_2025-2026_Base_Residual_Auction_20240114.pdf
January 16, 2024	IMM Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_ER24-98_20240116.pdf
January 24, 2024	IMM Answer to PJM Def Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Def_Answer_Docket_No_ER24-99_20240124.pdf
January 25, 2024	IMM Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Def_Answer_Docket_No_ER24-98_20240125.pdf
February 26, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2024/2025 and 2025/2026 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20240226.pdf
February 29, 2024	IMM Request for Rehearing re PJM CIFP Docket No. ER24-99-000, -001 https://www.monitoringanalytics.com/filings/2024/IMM_Request_for_Rehearing_Docket_No_ER24-99_20240229.pdf
February 29, 2024	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2025-2026_RPM_Base_Residual_Auction_Revised_20240229.pdf
April 3, 2024	EE Addback Education https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_EE_Addback_Education_20240403.pdf
April 18, 2024	IMM Determinations Posted for the PJM 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_Posted_for_the_PJM_%202025-2026_Base_Residual_Auction-Revised_20240418.pdf
May 31, 2024	IMM Complaint re Indicated EE Sellers Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Complaint_Docket_No_EL24-113_20240530.pdf
June 14, 2024	IMM Answer re IMM Complaint EE Suppliers Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Motion_Docket_No_EL24-113_20240614.pdf
June 25, 2024	IMM Answer re Elwood Waiver Request Docket No. ER24-2176 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_Opposing_Elwood_Waiver_Request_Docket_No_ER24-2176_20240625.pdf
June 25, 2024	IMM Answer re Elgin Waiver Request Docket No. ER24-2173 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_Opposing_Elgin_Waiver_Request_ER24-2173_20240625.pdf
June 28, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20240628.pdf
July 3, 2024	MMU Calculated Net Revenues for the 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Calculated_Net_Revenues_2026-2027_Base_Residual_Auction_20240703.pdf
July 8, 2024	Data Submission Window Opening for the 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2026-2027_Base_Residual_Auction_20240708.pdf
July 10, 2024	IMM Complaint re EE Payment Docket No. EL24-126 https://www.monitoringanalytics.com/filings/2024/IMM_Complaint_Docket_No_EL24-xxx_20240710.pdf
July 10, 2024	IMM Comments re JCA EE Complaint Docket No. EL24-118 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_EL24-118_20240710.pdf
July 10, 2024	IMM EE Package Proposal https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_EE_Package_Proposal_20240710.pdf
July 16, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20240716.pdf
July 24, 2024	IMM EE Package Proposal https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MRC_EE_Package_20240724.pdf
August 6, 2024	IMM Answer and Motion for Leave to Answer re IMM Complaint EE Suppliers Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Answer_Docket_No_EL24-113_20240806.pdf
August 15, 2024	IMM Answer and Motion for Leave to Answer and Motion for Summary Disposition re EE Docket No. EL24-126 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Answer_Docket_No_EL24-126_20240815.pdf
August 20, 2024	IMM Answer and Motion for Leave to Answer re CPower EE Complaint Docket No. EL24-128 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_EL24-128_20240820.pdf
September 5, 2024	IMM Determinations Posted for the PJM 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_Posted_for_the_PJM_2026-2027_Base_Residual_Auction_20240905.pdf
September 20, 2024	Analysis of the 2025/2026 RPM Base Residual Auction - Part A https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf
September 27, 2024	Data Submission Window Opening for the 2025/2026 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2025-2026_Third_Incremental_Auction_20240927.pdf
September 27, 2024	IMM Comments re EE Resources in the Capacity Market Docket No. ER24-2995 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_re_PJM_EE_Filing_Docket_No_ER24-2995_20240927.pdf
September 30, 2024	IMM Partial Offer of Settlement re EE Payments Complaint Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Offer_of_Settlement_Docket_No_EL24-113_20240930.pdf
October 10, 2024	IMM Comments re Sierra Club Complaint Docket No. EL24-148 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_EL24-148_20241010.pdf
October 14, 2024	IMM Answer and Motion for Leave to Answer re EE Resources in the Capacity Market Docket No. ER24-2995 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Comments_Docket_No_ER24-2995_20241014.pdf
October 15, 2024	Analysis of the 2025/2026 RPM Base Residual Auction - Part B https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf
October 18, 2024	IMM Comments re JCA EE Complaint Docket No. EL24-118 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_EL24-118_20241018.pdf
October 31, 2024	IMM Answer to Comments re Sierra Club Complaint Docket No. EL24-148 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_Docket_No_EL24-148_20241031.pdf
November 6, 2024	Analysis of the 2025/2026 RPM Base Residual Auction - Part C https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf
November 27, 2024	IMM Determinations Posted for the PJM 2025/2026 Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2025-2026_Third_Incremental_Auction_20241127.pdf
December 6, 2024	Analysis of the 2025/2026 RPM Base Residual Auction- Part D https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf
December 30, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20241230.pdf
January 6, 2025	IMM Comments re Capacity Market Rules Docket No. ER25-682 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-682_20250106.pdf
January 10, 2025	IMM Comments re Must Offer Exemption for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-785_20250110.pdf
January 14, 2025	IMM Answer to Motion to Extend re PA BRA Complaint Docket No. EL25-46 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Motion_to_Extend_Docket_No_EL25-46_20250114.pdf
January 23, 2025	IMM Comments re JCA Capacity Complaint Docket No. EL25-18 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_EL25-18_20250123.pdf

Market Design

With the earlier introduction of the Capacity Performance model and the recent introduction of the ELCC model, combined with a tightening of the capacity supply and demand balance in ICAP terms, it is clear that PJM's choices about the details of market design have a potentially dominant impact on capacity market outcomes in PJM.

RPM prices are locational and may vary depending on transmission constraints into LDAs and local supply and demand conditions.[53] The capacity market is not fully locational. The capacity market locational differences exist only across LDAs. The capacity market design assumes that there are no transmission or operational constraints within LDAs and treats all capacity resources within an LDA as perfect substitutes even when they are not. The lack of a fully locational design is a market design flaw that has resulted in the designation of units as RMRs based on internal constraints that were not recognized in the market clearing process. Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for categorically exempt intermittent and capacity storage resources including hydro, except for demand resources, and except for resources in a fixed resource requirement (FRR) plan. All load is required to pay for capacity. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. There are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Demand resources may be offered directly into RPM auctions but do not have a must offer obligation and do not have market seller offer caps and receive the clearing price.

The results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including by the CP design, by PJM's ELCC approach, by the definition of the maximum VRR price as gross CONE, by the failure to extend the RPM must offer requirement to all resources, including, in some cases, the exercise of market power through the withholding of categorically exempt resources, by the product definition and lack of market power mitigation for demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC market design and do also reflect, in part, the tightening of supply and demand conditions in the PJM Capacity Market.[54]

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unsupported assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created a new risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

The CP PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules

53 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

54 PJM's ELCC filing that created many of these issues was approved by FERC. 186 FERC ¶ 61,080 (January 30, 2024).

as exhibited most dramatically by the results of Winter Storm Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement. In addition, the imposition of PAI penalties on intermittent resources when those resources cannot perform is a key reason cited by PJM for the failure to apply the RPM must offer requirement uniformly.

In order to more accurately reflect resources' reliability contributions, ELCC should be significantly refined to include hourly data that would permit integrated unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, and CP should be modified to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. In the short run capacity accreditation should recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on the fixed cost of new generating capacity, or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin, and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin. The use of Net CONE was based on the logic of the capacity market, to ensure that the cost of entry was covered between the energy and capacity markets. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE and Gross CONE was used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on getting the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

Currently, intermittent and storage capacity resources are exempt from the RPM must offer requirement. In the 2025/2026 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,233.5 MW, or 40.9 percent of the required reserves and 39.2 percent of total reserves. Demand resources are also exempt from the RPM must offer requirement. Yet such resources combined make up more than two thirds (68.1 percent) of PJM's reserves. Given the growth of such resources and the expected growth based on the interconnection queue, that exemption should be eliminated immediately. The fact that more than two thirds of the PJM reserves depend on resources that are not subject to the RPM must offer requirement means that reliability is significantly less certain than the stated reserve margins indicate. Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights).

If some capacity resources hold CIRs that provide the access to the transmission system required for the deliverability of energy, but do not offer, those resources are exercising market power by blocking access to the transmission system that could be used by a resource willing to offer into the capacity market. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. The result of the failure to offer was a significant increase in the market price of capacity above the competitive level in the 2025/2026 BRA.

For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The MMU recommends that resources return CIRs to the market on the day of retirement. The same logic should be applied to intermittent and storage capacity resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues, issues of open access to the transmission system, and market power issues in the capacity market as the level of capacity from intermittent and storage capacity resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

Consistent with the must offer obligation, performance penalties should not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. If PAI is retained, this would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory.

Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

Installed Capacity

On January 1, 2024, RPM installed capacity was 178,375.0 MW (Table 5-3).[55] Over the next 12 months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 179,656.2 MW on December 31, 2024, an increase of 1,281.2 MW or 0.7 percent from the January 1 level.[56 57] The 1,281.2 MW increase was the net result of

55 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

56 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

57 Wind resources accounted for 3,321.4 MW, and solar resources accounted for 3,603.3 MW of installed capacity in PJM on January 1, 2024. Prior to the 2023/2024 Delivery Year, PJM administratively reduced the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data became available, unforced capability of wind and solar resources was to be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 19 (June 27, 2024). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.

new or reactivated generation (1,789.5 MW), net capacity modifications (1,048.8 MW), decreases in exports (109.0 MW), and increases in imports (17.1 MW) partially offset by derates (1,003.3 MW) and deactivations or changes in capacity resource status (679.9 MW).

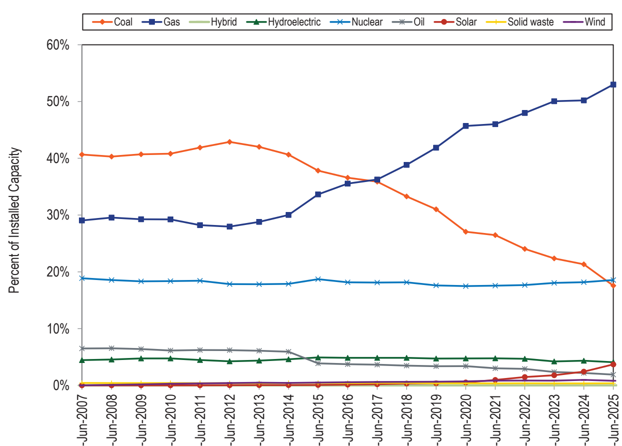
At the beginning of the new delivery year on June 1, 2024, RPM installed capacity was 176,985.3 MW, an increase of 365.6 MW or 0.0 percent from the May 31, 2023, level of 176,619.7 MW. This change occurs as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2024[58]

	01-Jan-24		31-May-24		01-Jun-24		31-Dec-24	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	21.9	0.0%	21.9	0.0%	21.5	0.0%	21.5	0.0%
Coal	37,936.3	21.3%	38,013.1	21.5%	37,751.4	21.3%	37,793.7	21.0%
Gas	88,868.7	49.8%	88,815.5	50.3%	88,860.7	50.2%	88,760.5	49.4%
Hybird	10.2	0.0%	10.2	0.0%	9.3	0.0%	9.3	0.0%
Hydroelectric	7,507.2	4.2%	7,507.2	4.3%	7,673.1	4.3%	7,674.7	4.3%
Nuclear	32,183.0	18.0%	32,180.5	18.2%	32,180.5	18.2%	32,179.9	17.9%
Oil	4,295.6	2.4%	4,184.4	2.4%	3,865.1	2.2%	3,965.9	2.2%
Solar	3,603.3	2.0%	3,780.6	2.1%	4,279.2	2.4%	5,046.5	2.8%
Solid waste	627.4	0.4%	627.4	0.4%	627.4	0.4%	609.4	0.3%
Wind	3,321.4	1.9%	1,478.9	0.8%	1,717.1	1.0%	3,594.8	2.0%
Total	178,375.0	100.0%	176,619.7	100.0%	176,985.3	100.0%	179,656.2	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2024, as well as the expected installed capacity for the 2025/2026 Delivery Year, based on the results of all auctions held through December 31, 2024.[59] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 21.3 percent on June 1, 2024, and is expected to decrease to 17.6 percent on June 1, 2025. The share of gas increased from 29.1 percent on June 1, 2007, to 50.2 percent on June 1, 2024, and is expected to increase to 53.0 percent on June 1, 2025.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2025



58 The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.
59 Due to ELCC values not being finalized for future delivery years, the expected installed capacity is based on cleared unforced capacity (UCAP) MW using the ELCC submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2024, through December 31, 2024, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and December 31, 2024

	01-Jan-24			31-May-24			01-Jun-24			31-Dec-24		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Constellation Energy Generation, LLC	20,288.1	13.9%	1	20,175.1	14.0%	1	20,137.0	14.1%	1	20,193.6	13.9%	1
ArcLight Capital Partners, LLC	12,115.2	8.3%	2	10,770.9	7.5%	3	10,521.1	7.4%	3	11,406.1	7.9%	4
LS Power Group	11,486.7	7.9%	3	11,485.7	8.0%	2	11,873.4	8.3%	2	12,691.6	8.7%	2
Talen Energy Corporation	10,167.9	7.0%	4	10,167.9	7.1%	4	10,169.2	7.1%	4	10,169.2	7.0%	5
Vistra Energy Corp.	8,669.4	6.0%	5	8,289.3	5.8%	5	8,177.1	5.7%	5	11,748.5	8.1%	3

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2024, to December 31, 2024, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2024

	01-Jan-24		31-May-24		01-Jun-24		31-Dec-24	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	131,830.6	73.9%	130,416.4	73.9%	129,209.8	73.0%	131,485.2	73.2%
Nonmarket	46,447.1	26.1%	46,106.0	26.1%	47,723.1	27.0%	48,171.0	26.8%
Total	178,277.7	100.0%	176,522.4	100.0%	176,932.9	100.0%	179,656.2	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[60] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are in Table 5-3. FDI_c calculations prior to June 1, 2023 included eight fuel types. Batteries were added to the resource mix on June 1, 2023, and hybrid solar resources were added on January 1, 2024. The maximum achievable index with nine fuel types is 0.889. The maximum achievable index with ten fuel types is 0.900. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[61] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[62] The average FDI_c for 2024 decreased 0.5 percent compared to 2023. Figure 5-2 also includes the expected FDI_c through December 2025. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c was used to measure the impact on fuel diversity of potential retirements in 2025 through 2030. A total of 34,733 MW of capacity are at risk of retirement, consisting of 4,684 MW currently planning to retire, 16,786 MW expected to retire for regulatory reasons and 13,264 MW expected to be uneconomic.[63] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2025 retirements were replaced by

60 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

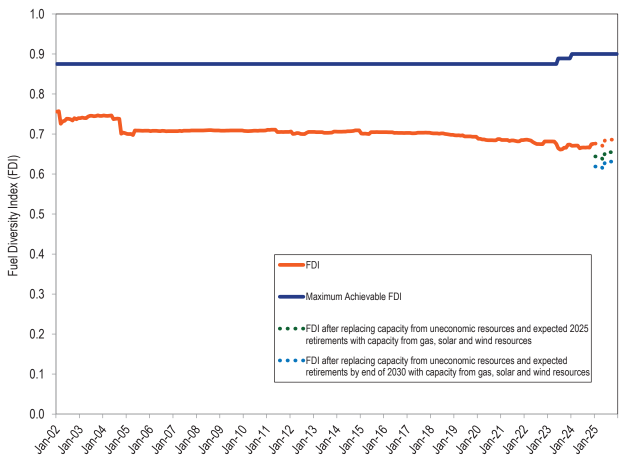
61 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 Annual State of the Market Report for PJM* for additional details.

62 See the *2019 Annual State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.

63 See the *2024 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

gas, wind and solar capacity.[64] The FDI_c under these assumptions would have been 4.7 percent lower than the actual FDI_c. The dotted blue line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected retirements through 2030 were replaced by gas, wind and solar capacity.[65] The counterfactual FDI_c in this scenario is 8.1 percent lower than the actual FDI_c.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through December 1, 2025



64 It is assumed that 620.6 MW of replacement capacity is from solar units and 718.4 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 11,907.4 GWh of generation in 2025 assuming the applicable PJM ELCC capacity derate factors and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-37. This level of GWh represents the increase in renewable generation required by RPS in 2025 over the level of renewable generation that was required by RPS in 2024. The split between solar and wind is based on queue data.

65 It is assumed that 2,871.8 MW of replacement capacity is from solar units and 3,324.8 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 55,110.7 GWh of generation in 2030 assuming the applicable PJM ELCC capacity derate factors and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-37. This level of GWh represents the increase in renewable generation required by RPS in 2030 over the level of renewable generation that was required by RPS in 2024. The split between solar and wind is based on queue data.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for intermittent and storage resources including hydro, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[66] In 2024, the 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction were conducted. The 2024/2025 RPM Base Residual Auction was initially conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement. Based on the FERC Order in Docket No. ER23-729-002, PJM reran the 2024/2025 RPM Base Residual Auction with final results posted on May 6, 2024, and PJM reran the 2024/2025 Third Incremental Auction with final results posted on May 23, 2024.[67] The 2025/2026 RPM Base Residual Auction was conducted in July 2024.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2023/2024 Delivery Year. The 12,863.0 MW increase was the result of new generation capacity resources (44,766.8 MW), reactivated generation capacity resources (1,380.4 MW), uprates (8,827.3 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (750.9 MW), offset by a net decrease in capacity imports (1,530.2 MW), deactivations (57,779.3 MW) and derates (5,520.4 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2021, through June 1, 2025, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent

66 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

67 187 FERC ¶ 61,065 (2024).

peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Prior to the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. Effective with the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the accredited UCAP factors for the delivery year are finalized, but before the start of the delivery day. Early replacement transactions can be approved for defined physical replacements.

Future Changes in Generation Capacity[68]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2023/2024 Delivery Year, internal installed capacity decreased by 8,325.2 MW after accounting for new capacity resources, reactivations, and uprates (54,974.5 MW) and capacity deactivations and derates (63,299.7 MW).

For the current and future delivery years (2024/2025 through 2025/2026), new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (3,272.9 MW) and pending deactivations (2,534.6 MW), PJM capacity is expected to increase by 738.3 MW through the 2025/2026 Delivery Year.

Table 5-6 Generation capacity changes: 2007/2008 through 2023/2024[69 70]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
2022/2023	4,743.2	0.0	417.0	0.0	(469.3)	(868.0)	7,460.5	302.0	(2,203.6)
2023/2024	2,696.8	0.0	420.5	0.0	(47.9)	1,067.8	5,149.2	1,441.1	(4,588.7)
Total	44,766.8	1,380.4	8,827.3	21,967.5	(1,530.2)	(750.9)	57,779.3	5,520.4	12,863.0

As shown in Table 5-7, based on current positions, total reserves on June 1, 2025, will be 21,015.2 MW, of which 870.9 MW (UCAP) are in excess of the required level of reserves, which is 20,144.3 MW (UCAP). In the 2025/2026 BRA, 13,143.2 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 3,745.8 MW of intermittent and storage resources (28.5 percent of the categorically exempt MW and 2.8 percent of total cleared MW) were not offered in the 2025/2026 BRA.

In the 2025/2026 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,233.5 MW, or 40.9 percent of the required reserves and 39.2 percent of total reserves. The cleared

68 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
69 The capacity changes in this report are calculated based on June 1 through May 31.
70 The uprate values for 2023/2024 and the derate values for 2022/2023 were revised from the *2024 Quarterly State of the Market Report for PJM: January through September.*

MW of DR is 6,085.6 MW, or 30.2 percent of required reserves and 29.0 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 14,319.1 MW, or 71.1 percent of required reserves and 68.1 percent of total reserves.

The fact that more than two thirds (68.1 percent) of the PJM reserves depend on resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.

Table 5-7 RPM reserve margin: June 1, 2021, to June 1, 2025[71] [72] [73]

	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	01-Jun-25	
Forecast peak load ICAP (MW)	149,482.9	149,263.6	149,382.2	151,631.1	153,883.0	A
FRR peak load ICAP (MW)	11,717.7	28,292.8	29,554.6	30,431.0	11,597.3	B
PRD ICAP (MW)	510.0	230.0	235.0	305.0	224.0	C
Installed reserve margin (IRM)	14.7%	14.9%	14.9%	17.7%	17.8%	D
Pool wide average EFORd	5.22%	5.08%	4.87%	5.10%		E
Pool wide accredited UCAP factor					79.69%	F
Forecast pool requirement (FPR)	1.087	1.091	1.093	1.117	0.939	G=(1+D)*(1-E) or G=(1+D)*F
RPM committed less deficiency UCAP (MW) (generation and DR)	156,633.6	137,944.8	136,401.8	138,318.6	134,224.2	H
RPM committed less deficiency ICAP (MW) (generation and DR)	165,260.2	145,327.4	143,384.6	145,751.9	168,432.9	J=H/(1-E) or J=H/F
RPM peak load ICAP (MW)	137,255.2	120,740.8	119,592.6	120,895.1	142,061.7	K=A-B-C
Reserve margin ICAP (MW)	28,005.0	24,586.6	23,792.0	24,856.9	26,371.2	L=J-K
Reserve margin (%)	20.4%	20.4%	19.9%	20.6%	18.6%	M=L/K
Reserve margin in excess of IRM ICAP (MW)	7,828.5	6,596.3	5,972.7	3,458.4	1,084.2	N=L-D*K
Reserve margin in excess of IRM (%)	5.7%	5.5%	5.0%	2.9%	0.8%	P=N/K
RPM peak load UCAP (MW)	130,090.5	114,607.2	113,768.4	114,729.4	113,209.0	Q=K*(1-E) or Q=K*F
RPM reliability requirement UCAP (MW)	149,210.1	131,679.9	130,714.7	135,039.8	133,353.3	R=K*G
Reserve margin UCAP (MW)	26,543.1	23,337.6	22,633.4	23,589.2	21,015.2	S=H-Q
Reserve cleared in excess of IRM UCAP (MW)	7,423.5	6,264.9	5,687.1	3,278.8	870.9	T=H-R
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	U
Projected reserve margin	20.4%	20.4%	19.9%	20.6%	18.6%	V=(J-U/(1-E))/K-1 or V=(J-U/F)/K-1

Sources of Funding[74]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2023/2024 Delivery Year totaled 46,147.2 MW (83.8 percent of all additions), with 36,021.6 MW from market funding and 10,135.6 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2023/2024 Delivery Year totaled 8,917.3 MW (16.2 percent of all additions), with 2,494.0 MW from market funding and 2,494.0 MW from nonmarket funding. In summary, of the 55,064.5 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2023/2024 Delivery Years, 42,444.9 MW (77.1 percent) were based on market funding.

Of the 8,966.4 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Years, 2,084.6 MW are not yet in service. Of those 2,084.6 MW that have not yet gone into service, 1,666.0 MW have market funding and 418.6 MW have nonmarket funding. Applying the historical completion rates, 65.0 percent of all the projects in development are expected to go into service (1,078.9 MW of the 1,666.0 MW of in development market funded projects; 277.1 MW of the 418.6 MW in development nonmarket funded projects).[75]

71 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
72 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
73 The RPM committed less deficiency MW values (rows H and J) and resultant reserve margin calculations for June 1, 2023, and June 1, 2024, were revised from the *2024 Quarterly State of the Market Report for PJM: January through September*.
74 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
75 See the *2023 Annual State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning.

Of the 6,881.8 MW of the additional generation capacity that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Years and are already in service, 3,866.6 MW (56.2 percent) are based on market funding and 3,015.2 MW (43.8 percent) are based on nonmarket funding.

In summary, 5,532.6 MW (61.7 percent) of the additional generation capacity (1,666.0 MW not yet in service and 3,866.6 MW in service) that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 3,433.8 MW (43.8 percent) of proposed generation that cleared the RPM auctions for the 2024/2025 and 2025/2026 Delivery Years.

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

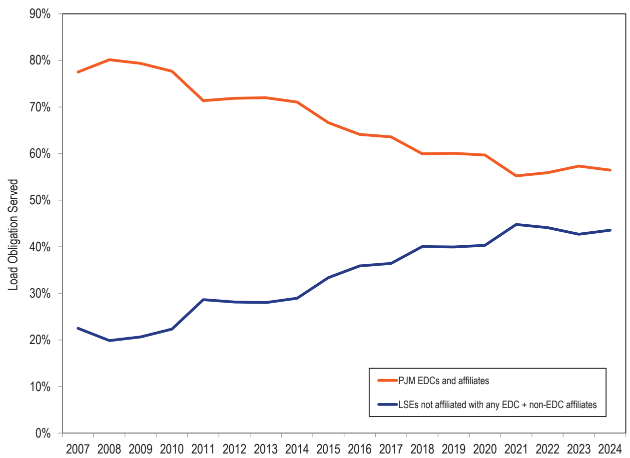
On June 1, 2024, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 56.4 percent (Table 5-8), down from 57.3 percent on June 1, 2023. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 43.6 percent, up from 42.7 percent on June 1, 2023. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2024, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 56.4 percent on June 1, 2024. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 43.6 percent on June 1, 2024.[76]

Table 5-8 Capacity market load obligation served: June 1, 2023 and June 1, 2024

	01-Jun-23		01-Jun-24		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	101,469.1	57.3%	106,462.1	56.4%	4,993.0	(0.9%)
LSEs not affiliated with any EDC + non EDC Affiliates	75,548.7	42.7%	82,180.1	43.6%	6,631.5	0.9%
Total	177,017.7	100.0%	188,642.2	100.0%	11,624.5	0.0%

76 Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2024



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted three months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run three months prior to the delivery year when auctions follow the traditional schedule.[77] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the

77 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 59 (June 27, 2024).

2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2025/2026 RPM Base Residual Auction, BGE had 4,990.0 MW of CTRs with a total value of $357.8 million and DOM had 1,903.3 MW of CTRs with a total value of 121.1 million.

BGE had 65.7 MW of customer funded ICTRs with a total value of $4.7 million.

BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of 21.9 million.

Demand Curve

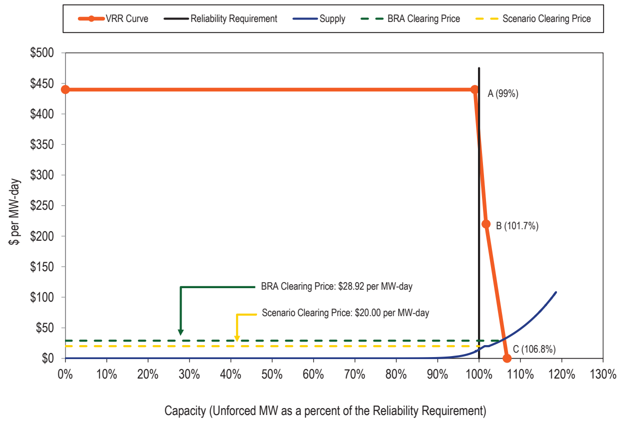
A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[78] Figure 5-4 shows the shape of the VRR curve for the 2025/2026 RPM Base Residual Auction.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity, which is the Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[79] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2025/2026 RPM BRA.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2025/2026 Delivery Year



78 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)].*

79 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[80] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[81 82 83]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2022/2023 through 2025/2026 RPM Auctions[84]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2022/2023 Third Incremental Auction				
RTO	0.68	0.50	43	43
MAAC	0.40	0.05	9	9
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2024/2025 Third Incremental Auction				
RTO	0.88	0.59	64	64
MAAC	0.60	0.17	10	10
EMAAC	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2025/2026 Base Residual Auction				
RTO	0.82	0.62	128	128
BGE	0.00	0.00	0	0
Dominion	0.00	0.00	0	0

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting

80 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
81 See OATT Attachment DD § 6.5.
82 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
83 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

84 The RSI shown is the lowest RSI in the market.

with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[85] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[86] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[87] [88] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[89]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[90]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[91] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market

85 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
86 OATT Attachment DD § 5.10 (a) (ii).
87 146 FERC ¶ 61,052 (2014).
88 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Volume 2, Section 5, "Capacity Market" at "Locational Deliverability Areas (LDAs)".
89 OATT Attachment DD § 5.6.6(b).
90 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (Dec. 21, 2017).
91 161 FERC ¶ 61,197 (2017).

seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[92] [93] [94] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[95]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[96] [97] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[98] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[99]

As shown in Table 5-10, of the 1,268.5 MW of imports offered in the 2025/2026 RPM Base Residual Auction, 1,268.5 MW cleared. Of the cleared imports, 700.5 MW (55.2 percent) were from MISO.

92 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
93 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 59 (June 27, 2024).
94 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 59 (June 27, 2024).
95 OATT Schedule 1 § 1.10.1A.
96 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
97 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 59 (June 27, 2024).
98 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
99 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

Table 5-10 RPM imports: 2007/2008 through 2025/2026 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6
2025/2026	700.5	700.5	568.0	568.0	1,268.5	1,268.5

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[100] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

Effective with the 2020/2021 Delivery Year, DR includes annual and summer products. Annual Demand Resources are required to be available on any day during the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT.

As shown in Table 5-11, and Table 5-12, committed DR was 7,699.9 MW for June 1, 2024, as a result of cleared capacity for demand resources in RPM auctions for the 2024/2025 Delivery Year (8,064.7 MW) less replacement capacity (364.8 MW).

100 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Table 5-11 RPM load management statistics by LDA: June 1, 2021 to June 1, 2025[101 102 103 104]

		UCAP (MW)															
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK	Dominion
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5	
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5	
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)	
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)	
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3	
01-Jun-22	DR cleared	8,866.2	2,821.3	1,139.9	489.2	48.4	294.6	93.8	325.3	949.4	191.8	1,521.9	163.9	661.7	210.5	185.1	
	EE cleared	5,734.8	2,303.6	1,265.3	499.4	53.5	431.0	201.6	287.5	485.0	55.9	792.6	211.9	312.4	129.4	186.8	
	DR net replacements	(570.0)	(395.4)	(138.0)	(12.6)	1.7	(49.4)	(12.6)	(21.5)	(99.6)	(28.2)	127.5	8.9	(165.2)	(24.1)	24.3	
	EE net replacements	(4.0)	11.8	7.0	14.9	0.0	(2.1)	15.4	8.7	(22.2)	(0.5)	0.0	6.2	(9.8)	(13.0)	0.0	
	RPM load management	14,027.0	4,741.3	2,274.2	990.9	103.6	674.1	298.2	600.0	1,312.6	219.0	2,442.0	390.9	799.1	302.8	396.2	
01-Jun-23	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4	
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3	
	DR net replacements	(466.2)	(229.5)	(3.8)	(4.9)	22.8	3.4	2.6	(25.0)	47.2	(63.4)	160.7	20.1	(123.3)	(24.0)	25.0	
	EE net replacements	(5.3)	(2.2)	(1.0)	7.6	9.0	11.6	13.7	7.6	(15.3)	(0.5)	(20.9)	0.0	(6.2)	(7.9)	0.7	
	RPM load management	13,599.0	4,618.3	2,312.5	915.8	143.3	731.1	352.8	456.4	1,399.9	171.8	2,354.2	459.4	760.0	279.8	365.4	
01-Jun-24	DR cleared	8,064.7	2,497.6	1,004.0	358.5	46.0	285.7	98.2	160.4	682.6	141.6	1,554.0	198.1	603.4	192.9	221.9	
	EE cleared	7,716.0	3,543.5	2,064.9	787.4	99.9	802.9	392.0	398.9	587.6	54.9	1,063.4	388.5	391.4	128.3	188.1	
	DR net replacements	(364.8)	(197.4)	9.1	43.0	35.2	(7.3)	(14.9)	19.3	50.9	(58.3)	(56.0)	23.7	(138.9)	(6.2)	(5.4)	
	EE net replacements	(48.0)	(43.6)	(15.4)	21.3	14.1	(6.5)	(0.1)	9.1	(30.6)	0.0	1.2	12.2	(38.4)	(5.6)	(3.7)	
	RPM load management	15,367.9	5,800.1	3,062.6	1,210.2	195.2	1,074.8	475.2	587.7	1,290.5	138.2	2,562.6	622.5	817.5	309.4	400.9	
01-Jun-25	DR cleared	6,064.7	1,844.9	782.7	295.5	65.0	228.9	65.8	132.5	546.1	67.3	1,086.9	163.0	422.5	140.1	159.6	673.5
	EE cleared	1,459.8	647.1	410.1	151.8	24.0	167.2	88.4	80.0	68.5	6.6	337.6	71.8	45.7	18.5	24.9	154.2
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	7,524.5	2,492.0	1,192.8	447.3	89.0	396.1	154.2	212.5	614.6	73.9	1,424.5	234.8	468.2	158.6	184.5	827.7

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2025[105 106 107]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	8,064.7	0.0	(364.8)	7,699.9	(507.4)	7,192.5	6,758.7	1.117	7,549.5
01-Jun-25	6,064.7	0.0	0.0	6,064.7	0.0	6,064.7	0.0	0.760	0.0

101 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
102 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
103 EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 delivery year, and EE resources are not defined to be capacity resources in any way as a result. EE resources do not clear in the capacity auctions.
104 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.
105 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
106 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
107 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Capacity Value of Intermittent Resources

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices at times of high intermittent output. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The contribution of intermittent and storage resources to reliability has been addressed in the PJM capacity market using derating factors in order to help ensure that MW of capacity are comparable, regardless of the source. Derating factors based on average generation during summer peak hours were used prior to the 2023/2024 Delivery Year to determine capacity values for wind and solar generators.[108] On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[109] The MMU opposed PJM's ELCC rules because they relied on significant counterfactual behavioral assumptions for storage and demand response resources, did not apply to all resource types, used invented (putative) data, used average technology values, were not locational, and provided for a long term guarantee of high average ELCC values for existing resources, among other issues.[110] PJM's ELCC approach is an ex ante, administrative determination by PJM based on a black box model, of the capacity value of resources. The ELCC values are on a class average technology class basis with no recognition of locational differences and no opportunity to recognize actual performance in the delivery year. PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability. Capacity values determined by the PJM average ELCC approach are being used for the 2023/2024 and 2024/2025 Delivery Years. On January 30, 2024, FERC accepted PJM's modified marginal ELCC approach and it was used to determine capacity values for the 2025/2026 Base Residual Auction held in July 2024.[111] PJM's modified marginal ELCC approach was used to determine the capacity values for thermal resources and demand resources in addition to the intermittent resources.

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability and consistent with a perfect resource, or at least a thermal resource. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense but PJM's implementation does not. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources, currently credited with full capacity value, that are much less available than some intermittent resources that are derated.

PJM's approach to ELCC is based on correct insights about the need to calculate the availability of different resource types but the actual implementation results in a set of illogical implications. For example, PJM assigned penalties to solar resources during winter storm Elliott in December 2022 when solar resources did not generate power after dark.

Under the PJM ELCC approach a solar resource is assigned a derating factor, the derated MW are equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of perfect capacity,

108 *Class Average Capacity Factors – Wind and Solar Resources*, PJM Interconnection L.L.C. (June 1, 2017).

109 See 176 FERC ¶ 61,056 (2021). There are multiple ways to apply the ELCC method. There is not a single ELCC method.

110 182 FERC ¶ 61,109 (2023).

111 186 FERC ¶ 61,080 (2024).

meaning capacity that is always available at the derated level, even in the middle of the night.[112] As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of intermittent and storage resources, or for thermal resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[113]

PJM's current approach to ELCC is a marginal approach in which the ELCC class rating should represent the carrying capability of an additional MW of ICAP for the resource class. In addition to intermittent and storage resources, the approach is used to determine the capacity values for thermal resources and demand resources. Most of the issues with the prior average ELCC approach also apply to the new marginal approach. The new marginal approach relies on significant counterfactual behavioral assumptions for storage and demand resources, uses invented (putative) data, is not unit specific, is not hourly, is not locational, and is an ex ante approach that must assume a capacity resource fleet for determining the ELCC marginal class ratings.

The ELCC ratings produced by the marginal approach in general, and by PJM's specific marginal approach specifically, are inherently volatile. PJM has calculated the marginal ELCC class ratings for the 2025/2026 delivery year on five separate occasions. Table 5-13 shows the results of each calculation. Each calculation is dependent upon the load forecast model, the combination of actual historical performance and changes in experienced weather, and the assumed forward looking resource mix. The PJM 2024 load forecast model was used to produce the February 2024, March 2024 and January 2025 ELCC ratings. The ELCC ratings posted on December 31, 2024, used an interim 2025 load forecast model. In early January, PJM removed the posted ELCC ratings from December 31, 2024, and posted recalculated ratings using the 2024 load forecast model. The modified ELCC ratings were posted on January 23, 2025. The January 23, 2025, ratings are the final ELCC ratings for 2025/2026 Delivery Year.[114] The ELCC rating changes have significant impacts on the amount of cleared capacity. Table 5-14 shows the difference between capacity that cleared the 2025/2026 Base Residual Auction and the updated capacity MW value based on the final ELCC ratings for 2025/2026 posted on January 23, 2025. In total, the capacity values decreased by 928.5 MW (UCAP) or 0.7 percent. Capacity market sellers are obligated to obtain additional capacity prior to the delivery year if they are short as a result of a reduction in ELCC rating between the BRA and the final ELCC rating from PJM's ELCC rating changes. Had PJM used the ELCC ratings posted on December 31, 2024, the capacity values would have decreased by 3,793.3 or 2.8 percent.

Table 5-13 Marginal ELCC ratings for the 2025/2026 Delivery Year

	2025/2026 Delivery Year				
ELCC Class	December 2023	February 2024	Ratings for Base Residual Auction March 2024	Dec 31, 2024	Ratings for Third Incremental Auction Jan 23, 2025
Onshore Wind	21%	35%	35%	42%	38%
Offshore Wind	39%	60%	60%	71%	62%
Solar Fixed	15%	9%	9%	8%	10%
Solar Tracking	25%	14%	14%	11%	14%
Landfill Intermittent	56%	55%	54%	51%	51%
Hydro Intermittent	41%	36%	37%	37%	37%
4-hr Storage	76%	59%	59%	44%	55%
6-hr Storage	85%	67%	67%	53%	65%
8-hr Storage	89%	69%	68%	58%	68%
10-hr Storage	92%	78%	78%	67%	77%
Demand Response	95%	77%	76%	68%	77%
Nuclear	96%	96%	95%	95%	95%
Coal	86%	85%	84%	83%	83%
Gas Combined Cycle	87%	80%	79%	77%	78%
Gas Combustion Turbine	74%	62%	62%	59%	63%
Gas Combustion Turbine Dual Fuel	90%	78%	79%	78%	79%
Diesel Utility	91%	90%	92%	92%	92%
Steam	78%	70%	75%	73%	74%

112 "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection L.L.C. (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
113 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.
114 See Item 5 in Markets and Reliability Committee Meeting Materials, *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2025/2026 3IA* at 2, PJM Interconnection L.L.C. (January 23, 2025) <https://www.pjm.com/committees-and-groups/committees/mrc>.

Table 5-14 Impact of ratings changes on cleared capacity[115]

	MW (UCAP)	Reduction in capacity value compared to Base Residual Auction	Percent change in capacity value compared to Base Residual Auction
2025/2026 Base Residual Auction Cleared Capacity	135,684.0		
Updated Cleared Capacity based on Jan 23, 2025 ELCC Ratings	134,755.5	(928.5)	(0.7%)
Updated Cleared Capacity based on Dec 31, 2024 ELCC Ratings	131,890.7	(3,793.3)	(2.8%)

The December 31, 2024, ELCC ratings are based on an interim PJM 2025 load forecast model. PJM never explained why the December 31, 2024, ratings are not a better indicator of the expected capacity values than the values based on the PJM 2024 load forecast model and posted by PJM on January 23, 2025. If the more current forecast is a better indicator of expected capacity values, the capacity cleared for the 2025/2026 BRA actually has a capacity value of 131,890.7 MW (UCAP), or 2,864.8 MW (UCAP) less than the capacity value obtained using the ratings based on the outdated PJM 2024 load forecast and posted by PJM on January 23, 2025.

The ELCC volatility also affects the reliability requirement calculation. Table 5-15 shows the reliability requirement calculation for the 2025/2026 RPM Base Residual Auction and the recently posted update for the Third Incremental Auction for 2025/2026.[116] The pool wide accredited UCAP factor for the Third IA is based on the January 23, 2025, ELCC ratings which use the PJM 2024 load forecast model. These updated ELCC ratings reduced the pool wide accredited UCAP factor from 0.7969 to 0.7963. The reliability requirement and the FRR obligation both increase, resulting in an increase of 395.7 MW (UCAP) to the reliability requirement adjusted for FRR. PJM needs to procure an additional 395.7 MW (UCAP) of capacity in the Third Incremental Auction. PJM procures the capacity by submitting buy bids in the Third Incremental Auction.[117]

Table 5-15 PJM Reliability Requirement

	2025/2026 Base Residual Auction	2025/2026 Third Incremental Auction	Change
ICAP	191,693.0	188,920.0	
Solved Load	160,624.0	158,357.0	(2,267.0)
Installed Reserve Margin	17.800%	17.800%	0.0%
Accredited UCAP	152,765.0	150,438.0	(2,327.0)
Pool Wide Accredited UCAP Factor	0.797	0.796	(0.001)
Forecast Pool Requirement	0.939	0.938	(0.001)
Preliminary Forecast Peak Load	153,883.0	154,534.1	651.0
Reliability Requirement	144,450.0	144,953.0	503.0
Fixed Resource Requirement (FRR)	10,886.4	10,993.7	107.3
Reliability Requirement Adjusted for FRR	133,563.6	133,959.3	395.7

The calculated impact of the PJM 2025 load forecast model on the reliability requirement was not provided by PJM.

The capacity derating factors applied to intermittent nameplate capacity for the 2022/2023 Delivery Year and the ELCC calculations used for the 2023/2024 and the 2024/2025 Delivery Years were based on the assumption that intermittent resources provide reliable output in excess of their CIRs. However, that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity. The preferable solution is to require intermittent resources to purchase CIRs equal to the maximum energy output assumed in the ELCC derating calculation. That is the solution reached in the PJM stakeholder process.[118] The corresponding performance obligation of an intermittent resource is to produce at its corresponding maximum energy output level when it is possible, based on wind and solar conditions. After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[119]

115 PJM stated that the 2024 load forecast model was used because it is the "most recently finalized PJM load forecast." The January 23, 2025, ELCC Ratings are based on the PJM 2024 load forecast model. The December 31, 2024, ELCC Ratings are based on an interim PJM 2025 load forecast model.
116 *2025/2026 RPM 3rd Incremental Auction Planning Parameters*, PJM Interconnection L.L.C. (January 31, 2025) <https://www.pjm.com/markets-and-operations/rpm>.
117 Id.
118 ELCC/CIR discussions were held throughout 2022 during the PC Special Session – CIRs for ELCC Resources as well as the MC and the MRC<https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=83aadda8-b6c1-4630-9483-025b6b93fc28>.
119 183 FERC ¶61,009.

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. There is the related issue of ensuring that intermittent resources, like all other resources, are required to pay their own interconnection costs in order to meet their attributed capacity value, consistent with the longstanding PJM market design, or reduce their capacity value.

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs).[120] If the intermittent resource or environmentally limited resource is deemed deliverable by PJM based on the additional CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year. Winter seasonal products have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. But this system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer.

PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. Those CIRs are not available to be sold to or provided to intermittent resources because they have been paid for by annual resources. The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules.

120 OATT Part VII, Subpart E § 332.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[121] [122] [123] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps were defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[124] The Commission rejected a more recent attempt to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[125]

For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[126] As a result, the tariff

121 See OATT Attachment DD § 6.5.
122 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
123 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
124 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023), *cert. denied*.
125 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
126 OATT Attachment DD § 6.8(b).

defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[127] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts, including RECs, and expected bonus performance payments/nonperformance charges.[128] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[129]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[130] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR), the resource's gross ACR, and the resource's forward looking net revenues. The gross ACR includes the cost to mitigate the resource's risk of incurring performance assessment penalties.

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel prices are a better guide to market expectations than historical energy and fuel prices. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices. The forward curves reflect this change, but the historical prices do not. However the PJM method for calculating forward looking net revenues is significantly flawed and overestimates net revenues.

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 Delivery Year.[131] FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.[132] PJM's method for calculating forward looking E&AS net revenues was flawed for several reasons. PJM's method included an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an

127 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).

128 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

129 OATT Attachment DD § 6.8(a).

130 151 FERC ¶ 61,208 (2015).

131 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).

132 Forward energy and ancillary services (E&AS) revenue offsets were applicable from November 12, 2020, as approved in the FERC Order on compliance in Docket Nos. EL19-58-002 and EL19-58-003 until December 22, 2021, when the Commission issued an Order on Voluntary Remand in Docket Nos. EL19-58-006 and ER19-1486-003 reversing its prior determination that PJM should use a forward looking energy E&AS revenue offset and directing PJM to submit a compliance filing restoring the tariff provisions defining the historical E&AS revenue offset.

adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[133]

More fundamentally, PJM's forward looking net revenue calculation tends to overestimate forward net revenues. The PJM method is based on a theoretical, unit by unit perfect dispatch based on unit parameters and forward fuel costs and LMPs. The PJM method fails to account for the realities of committing and dispatching units. Nonetheless, it remains correct that generation owners look forward and not backwards when calculating net revenues. The goal is an approach that retains the reality of historical commitment and dispatch while recognizing that future conditions will be different. A better approach would calculate unit forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel.

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[134]

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the Net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.[135] The Commission rejected a more recent attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[136]

2024/2025 RPM Third Incremental Auction

As shown in Table 5-16, 320 generation resources submitted Capacity Performance offers in the 2024/2025 RPM Third Incremental Auction. Unit specific offer caps were calculated for seven generation resources (2.2 percent). Of the 320 generation resources, 223 generation resources elected the offer cap option of 1.1 times the BRA clearing price (69.7 percent), 62 generation resources had default ACR based offer caps (19.4 percent), five generation resources had unit specific ACR based offer caps (1.5 percent), two generation resource had a unit specific opportunity cost based offer cap (0.6 percent), two Planned Generation Capacity Resources had uncapped offers (0.6 percent), and the remaining 26 generation resources were price takers (8.1 percent). Market power mitigation was applied to seven Capacity Performance sell offers. Based on the FERC Order in Docket No. ER23-729-002, PJM reran the 2024/2025 Third Incremental Auction with final results posted on May 23, 2024.[137]

2025/2026 RPM Base Residual Auction

As shown in Table 5-16, 1,119 generation resources submitted Capacity Performance offers in the 2025/2026 RPM Base Residual Auction. Unit specific offer caps

133 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 45 (Sep. 1, 2024).

134 OATT Attachment DD § 10A (d).

135 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).

136 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).

137 187 FERC ¶ 61,065 (2024).

were calculated for 61 generation resources (5.5 percent). Of the 1,119 generation resources, 729 generation resources had default ACR based offer caps (65.1 percent), 46 generation resources had unit specific ACR based offer caps (4.1 percent), 15 generation resource had a unit specific opportunity cost-based offer cap (1.3 percent), 25 Planned Generation Capacity Resources had uncapped offers (2.2 percent), one generation resource had an uncapped planned uprate and default ACR based offer cap for the existing portion (0.1 percent), and the remaining 303 generation resources were price takers (27.1 percent). Market power mitigation was applied to sell offers of 16 generation resources.

Table 5-16 ACR statistics: RPM auctions held in 2024

	2024/2025 Third Incremental Auction		2025/2026 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	62	19.4%	729	65.1%
Unit specific ACR (APIR)	3	0.9%	1	0.1%
Unit specific ACR (APIR and CPQR)	0	0.0%	11	1.0%
Unit specific ACR (non-APIR)	2	0.6%	5	0.4%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	29	2.6%
Opportunity cost input	2	0.6%	15	1.3%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	223	69.7%	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	1	0.1%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	2	0.6%	25	2.2%
Existing generation resources as price takers	26	8.1%	303	27.1%
Total Generation Capacity Resources offered	320	100.0%	1,119	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[138] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[139] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[140]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[141] The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is

138 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020), *aff'd* PJM Power Providers Group, et al. v. FERC, Case No. 21-3068 (3rd Cir. December 1, 2023), *cert denied.*
139 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
140 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
141 *PJM Interconnection, L.L.C,* Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).

defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[142]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking E&AS offset to include forward looking energy and ancillary services revenues rather than historical.[143] The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.[144]

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-17, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2024/2025 RPM Third Incremental Auction or the 2025/2026 RPM Base Residual Auction. Of the 734.0 MW offered in the 2024/2025 RPM Third Incremental Auction that were subject to MOPR, 673.3 MW cleared and 60.7 MW did not clear. Of the 212.6 MW offered in the 2025/2026 RPM Base Residual Auction that were subject to MOPR, 212.0 MW cleared and 0.6 MW did not clear.

Table 5-17 MOPR statistics: RPM auctions held in 2024

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2024/2025 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	833.3	734.0	673.3
	Total		0	0.0	0.0	833.3	734.0	673.3
2025/2026 Base Residual Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	634.7	212.6	212.0
	Total		0	0.0	0.0	634.7	212.6	212.0

Replacement Capacity[145]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-18 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2025.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high

142 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).
143 173 FERC ¶ 61,134 (2020).
144 177 FERC ¶ 61,209 (2021).
145 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation.

Table 5-18 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2025[146]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(5,517.6)	144,626.3	(2,363.5)	142,262.8
01-Jun-24	154,362.5	0.0	(4,046.2)	150,316.3	(4,377.2)	145,939.1
01-Jun-25	135,684.0	0.0	0.0	135,684.0	0.0	135,684.0

Market Performance

Figure 5-5 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-19 shows RPM clearing prices for the 2021/2022 through 2025/2026 Delivery Years for all RPM auctions

146 The RPM Commitment Shortage MW for June 1, 2023, and June 1, 2024, were revised from the *2024 Quarterly State of the Market Report for PJM: January through September.*

held through 2024, and Table 5-20 shows the RPM cleared MW for the 2021/2022 through 2025/2026 Delivery Years for all RPM auctions held through 2024.

Figure 5-6 shows the RPM cleared MW weighted average prices for each LDA from the 2022/2023 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through 2024. A summary of these weighted average prices is given in Table 5-21.

Table 5-22 shows RPM revenue by delivery year for all RPM auctions held through 2024 based on the unforced MW cleared and the resource clearing prices. For the 2024/2025 Delivery Year, RPM revenue is $2.6 billion. For the 2025/2026 Delivery Year, RPM revenue is $14.7 billion.

Table 5-23 shows RPM revenue by calendar year for all RPM auctions held through 2024. In 2024, RPM revenue is $2.5 billion. In 2025, RPM revenue is $9.7 billion.

Table 5-24 shows the RPM annual charges to load. For the 2023/2024 Delivery Year, annual charges to load were $2.2 billion. For the 2024/2025 Delivery Year, annual charges to load are $2.5 billion.

Table 5-19 Capacity market clearing prices: 2021/2022 through 2025/2026 RPM Auctions

		RPM Clearing Price ($ per MW-day)														
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55	$20.55
2022/2023 BRA	Capacity Performance	$50.00	$95.79	$50.00	$95.79	$97.86	$95.97	$97.86	$97.86	$97.86	$95.79	$50.00	$68.96	$126.50	$71.69	$50.00
2022/2023 Third Incremental Auction	Capacity Performance	$19.00	$35.00	$19.00	$35.00	$35.00	$96.15	$35.00	$35.00	$35.00	$35.00	$19.00	$19.00	$35.00	$19.00	$19.00
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$53.60	$49.49	$426.17	$53.60	$53.60	$49.49	$28.92	$28.92	$73.00	$96.24	$28.92
2024/2025 Third Incremental Auction	Capacity Performance	$58.00	$80.00	$58.00	$80.00	$175.81	$80.00	$175.81	$175.81	$175.81	$80.00	$58.00	$58.00	$155.29	$58.00	$58.00
2025/2026 BRA	Capacity Performance	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$466.35	$269.92	$444.26

Table 5-20 Capacity market cleared MW: 2021/2022 through 2025/2026 RPM Auctions[147]

		UCAP (MW)														
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM	TOTAL
2021/2022	BASE	26,552.8	12,565.1	10,136.1	15,368.6	22,286.8	1,673.8	2,237.7	3,134.1	6,013.2	8,010.5	22,358.1	4,200.7	2,746.1	26,343.7	163,627.3
2021/2022	FIRST	118.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	75.4	2,143.2
2021/2022	SECOND	1,082.0	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	160.5	3,707.5
2021/2022	THIRD	1,243.7	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	394.7	5,235.0
2022/2023	BASE	29,596.0	12,804.7	10,147.4	14,118.7	23,651.2	1,312.9	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	8,136.3	144,477.3
2022/2023	THIRD	703.3	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	395.7	5,987.9
2023/2024	BASE	28,642.1	10,098.5	8,145.5	14,352.7	22,912.6	1,412.8	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	8,266.7	145,066.9
2023/2024	THIRD	255.9	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	59.8	5,077.0
2024/2025	BASE	28,760.7	10,854.4	8,874.0	14,178.1	23,135.1	1,448.6	2,665.3	3,494.3	3,429.7	9,720.6	25,156.1	5,056.5	2,062.1	8,646.1	147,481.5
2024/2025	THIRD	365.3	744.8	815.6	665.2	963.0	33.2	48.7	60.2	78.7	245.6	2,370.0	222.5	90.2	177.9	6,881.0
2025/2026	BRA	24,573.1	9,490.1	8,481.3	12,368.8	19,043.0	958.7	1,894.3	2,520.1	2,274.4	7,778.5	21,814.2	2,800.6	1,636.7	20,050.2	135,684.0

147 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-21 Weighted average clearing prices by zone: 2021/2022 through 2025/2026

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2022/2023	2023/2024	2024/2025	2025/2026
RTO				
AEP	$49.35	$34.21	$29.80	$269.92
APS	$49.35	$34.21	$29.80	$269.92
ATSI	$48.89	$34.26	$29.80	$269.92
Cleveland	$49.41	$34.21	$28.92	$269.92
COMED	$63.70	$34.27	$31.42	$269.92
DAY	$49.16	$34.17	$29.13	$269.92
DUKE	$70.57	$34.24	$94.57	$269.92
DUQ	$49.35	$34.21	$29.80	$269.92
DOM	$49.35	$34.21	$29.80	$444.25
EKPC	$49.35	$34.21	$29.80	$269.92
MAAC				
EMAAC				
ACEC	$96.31	$52.21	$58.47	$269.92
DPL	$96.31	$52.21	$58.47	$269.92
DPL South	$97.41	$71.26	$420.55	$269.92
JCPLC	$96.31	$52.21	$58.47	$269.92
PECO	$96.31	$52.21	$58.47	$269.92
PSEG	$90.67	$50.71	$55.54	$269.92
PSEG North	$89.21	$50.73	$55.48	$269.92
REC	$96.31	$52.21	$58.47	$269.92
SWMAAC				
BGE	$119.73	$70.65	$77.88	$465.38
PEPCO	$94.75	$49.46	$50.12	$269.92
WMAAC				
MEC	$94.49	$49.49	$51.07	$269.92
PE	$94.49	$49.49	$51.07	$269.92
PPL	$95.29	$49.49	$51.18	$269.92

Table 5-22 RPM revenue by delivery year: 2007/2008 through 2025/2026[148]

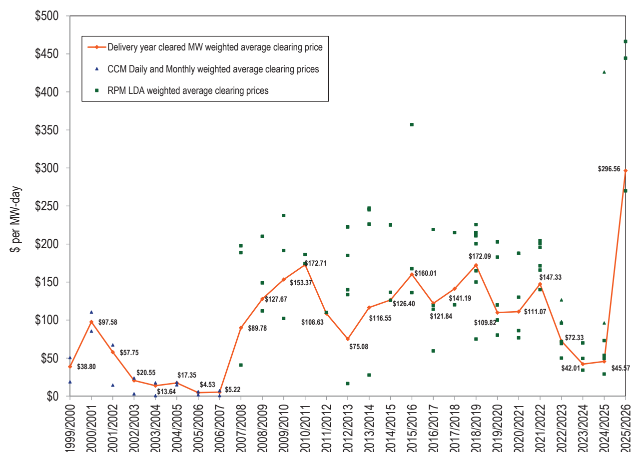
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.01	150,143.9	366	$2,308,670,914
2024/2025	$45.57	154,362.5	365	$2,567,491,013
2025/2026	$296.56	135,684.0	365	$14,687,047,370

148 The results for the ATSI Integration Auctions are not included in this table.

Table 5-23 RPM revenue by calendar year: 2007 through 2026[149]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.56	150,036.3	365	$2,993,266,921
2024	$44.09	152,857.8	366	$2,464,115,790
2025	$192.73	143,411.3	365	$9,673,203,507
2026	$296.56	56,132.3	151	$6,076,011,378

Figure 5-5 History of capacity prices: 1999/2000 through 2025/2026[150]



149 The results for the ATSI Integration Auctions are not included in this table.

150 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2025/2026 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-6 Map of RPM capacity prices: 2022/2023 through 2025/2026

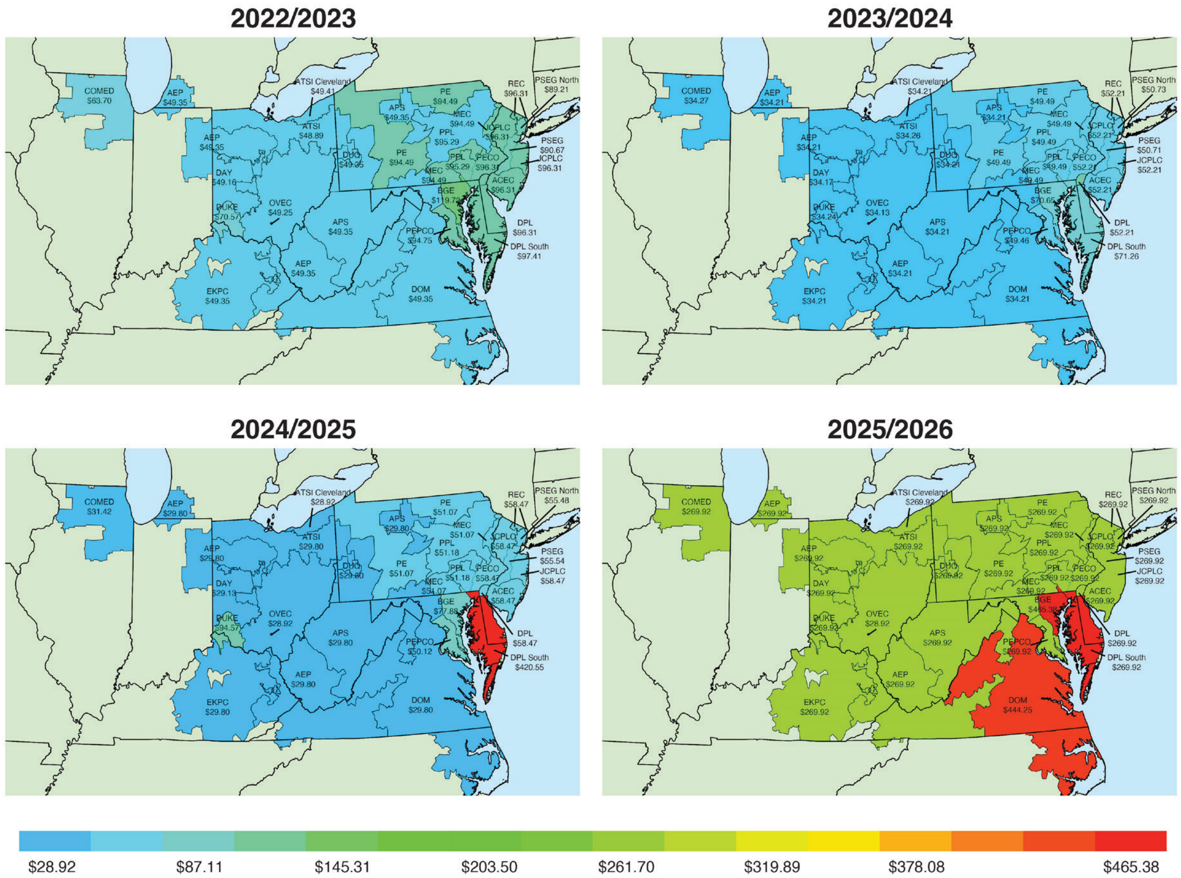


Table 5-24 RPM cost to load: 2022/2023 through 2025/2026 RPM Auctions[151 152 153]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DEOK	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
Rest of EMAAC	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$29.50	77,398.7	$833,520,097
EMAAC	$56.56	32,270.3	$666,184,144
WMAAC	$50.22	22,872.2	$419,263,035
Rest of EMAAC	$175.22	4,590.0	$293,561,344
BGE	$61.53	7,726.0	$173,527,700
DEOK	$57.93	5,254.4	$111,105,639
Total		150,111.7	$2,497,161,960
2025/2026			
Rest of RTO	$270.35	107,762.5	$10,633,606,312
BGE	$306.98	5,968.6	$668,769,284
DOM	$429.57	21,952.9	$3,442,062,633
		135,684.0	$14,744,438,229

151 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
152 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.
153 The net load prices and obligation MW for 2025/2026 are not final.

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[154 155 156 157 158 159] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

154 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).
155 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).
156 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).
157 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).
158 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).
159 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the prior MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

Dominion Energy Virginia elected the FRR option for the 2022/2023 through 2024/2025 delivery years but returned to the capacity market for the 2025/2026 BRA.

CRF Issue[160]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[161] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[162] [163]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{\mathrm{j}=1}^{\mathrm{L}} \frac{\mathrm{m_j}}{(1+\mathrm{r})^{\mathrm{j}}}\right]}{(1-s)\sqrt{1+\mathrm{r}}\,[(1+r)^N - 1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[164] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-26 shows the CRFs that are currently posted. The values in Table 5-26 were calculated using the formula above and the financial assumptions in Table 5-27. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

160 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
161 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
162 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
163 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.
164 176 FERC ¶61,003 (2021).

Table 5-25 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For example, Table 5-26, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[165] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-26 for delivery years after 2023/2024 would not apply to the calculation of APIR values for projects that go into service for the 2023/2024 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission stated that the issue is beyond the scope of the PJM filing.[166]

Table 5-26 Levelized CRF values: Delivery Year 2023/2024 through Delivery Year 2026/2027

Age of Unit (Years)	Cost Recovery Period	2023/2024	2024/2025	2025/2026	2026/2027
		Bonus Depreciation Percent			
		80%	60%	40%	20%
1 to 5	30	0.091	0.094	0.096	0.105
6 to 10	25	0.096	0.098	0.101	0.110
11 to 15	20	0.104	0.107	0.110	0.118
16 to 20	15	0.119	0.122	0.126	0.134
21 to 25	10	0.152	0.158	0.164	0.174
25 Plus	5	0.258	0.271	0.283	0.301
Mandatory CapEx	4	0.312	0.328	0.345	0.367
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-27 Financial parameter and tax rate assumptions for CRF calculations

Parameter	Parameter Values: Prior to 2026/2027	2026/2027
Equity Funding Percent	45.000%	45.000%
Debt Funding Percent	55.000%	55.000%
Equity Rate	13.000%	14.100%
Debt Interest Rate	6.000%	6.300%
Federal Income Tax Rate	21.000%	21.000%
State Income Tax Rate	9.300%	9.933%
Effective Income Tax Rate	28.347%	28.847%
After Tax Weighted Average Cost of Capital	8.215%	8.810%

The 2021 update to the CRF values was calculated using the weighted average cost of capital (WACC) model. The original CRF values, prior to 2021, were calculated using a flow to equity (FTE) model. The WACC model assumes a constant debt to equity ratio during the capital recovery period and therefore assumes that debt holders are paid more quickly than is required. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. Table 5-28 compares CRFs calculated under the two approaches using the assumptions in Table 5-27. The difference between the WACC CRF and FTE CRF is dependent upon the capital recovery term and the level of bonus depreciation. The WACC CRF exceeds the FTE CRF by 16.4 percent under 100 percent bonus depreciation with a 30 year cost recovery term. The FTE model is the correct approach because it accurately captures the cash flows during capital recovery over the defined financial life of the asset.

165 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.
166 176 FERC ¶61,003 at P 28 (2021).

Table 5-28 Comparison of FTE and WACC CRFs

Capital Recovery Term (years)	WACC CRF						FTE CRF					
	Bonus Percent						Bonus Percent					
	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.296	0.312	0.328	0.345	0.361	0.377	0.289	0.307	0.324	0.342	0.360	0.377
5	0.246	0.258	0.271	0.283	0.296	0.308	0.238	0.252	0.266	0.280	0.294	0.308
10	0.147	0.152	0.158	0.164	0.169	0.175	0.138	0.145	0.153	0.160	0.168	0.175
15	0.116	0.119	0.122	0.126	0.129	0.132	0.105	0.111	0.116	0.122	0.127	0.133
20	0.101	0.104	0.107	0.110	0.113	0.115	0.090	0.095	0.100	0.105	0.110	0.115
25	0.093	0.096	0.098	0.101	0.104	0.106	0.081	0.086	0.091	0.096	0.100	0.105
30	0.088	0.091	0.094	0.096	0.099	0.101	0.076	0.081	0.085	0.090	0.095	0.099
Capital Recovery Term (years)	Absolute Change (WACC CRF less FTE CRF)						Relative Change					
	Bonus Percent						Bonus Percent					
	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.007	0.005	0.004	0.003	0.001	-0.000	2.3%	1.8%	1.2%	0.8%	0.3%	(0.1%)
5	0.007	0.006	0.004	0.003	0.001	-0.000	3.1%	2.3%	1.6%	1.0%	0.4%	(0.1%)
10	0.009	0.007	0.005	0.003	0.002	-0.000	6.5%	4.9%	3.4%	2.1%	0.9%	(0.2%)
15	0.010	0.008	0.006	0.004	0.002	-0.000	9.5%	7.2%	5.0%	3.1%	1.3%	(0.3%)
20	0.011	0.009	0.007	0.005	0.003	0.000	12.2%	9.3%	6.7%	4.4%	2.3%	0.4%
25	0.012	0.010	0.007	0.005	0.003	0.001	14.4%	11.2%	8.2%	5.6%	3.2%	1.1%
30	0.012	0.010	0.008	0.006	0.004	0.002	16.4%	12.8%	9.6%	6.7%	4.1%	1.7%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-29). The result is no change to the effective period between the notice and the retirement if notice is provided on the last day of the submittal period, and an increase to six months notice if notice is given on the first day of the submittal period. The MMU recommends that participants be required to provide a notice of deactivation 12 months prior to an auction in which the unit will not be offered due to the deactivation; and no less than 12 months prior to the date of deactivation.

Table 5-29 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following clendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[167] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[168]

Table 5-30 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through December 2024. Of the 199 deactivation requests submitted, 31 units (15.6 percent) deactivated an average of 157 days earlier than their initially requested date; 30 units (15.1 percent) deactivated an average of 103 days later than the originally requested deactivation date; and 79 units (39.7 percent) deactivated on their initially requested date. Twenty four (12.1 percent) of the unit deactivations were cancelled an average of 256 days (approximately 37 weeks) before their scheduled deactivation date, and 35 (17.6 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-31 shows this information broken out by fuel types.

Due to the significant increase in the capacity price for the 2025/2026 Delivery Year, several units that were scheduled to deactivate rescinded their deactivation request. In 2024, Middle River Power, LLC, rescinded the deactivation of 483 MW from the Elgin CT 1-4 units.

167 OATT Attachment DD § 6.6(g).
168 OATT Part V §113.

At least nine other units that were slated to deactivate, accounting for 454.4 MW, have said they will rescind their deactivation requests as a result of the 2025/2026 BRA clearing prices.

Table 5-30 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through December 2024[169]

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	31	15.6%	(157)
Late	30	15.1%	103
On time	79	39.7%	0
Cancelled	24	12.1%	(256)
Pending	35	17.6%	-
Total	199	100.0%	-

169 Negative values indicate the average number of days the action is taken prior to the requested date.

Table 5-31 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through December 2024

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	66.7%	(4)
	Late	1	33.3%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	3	100.0%	-
Coal	Early	15	31.3%	(169)
	Late	9	18.8%	78
	On time	16	33.3%	0
	Cancelled	4	8.3%	(371)
	Pending	4	8.3%	-
	Total	48	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	5	83.3%	-
	Cancelled	0	0.0%	-
	Pending	1	16.7%	-
	Total	6	100.0%	-
Methane	Early	4	15.4%	(107)
	Late	7	26.9%	71
	On time	11	42.3%	0
	Cancelled	2	7.7%	(190)
	Pending	2	7.7%	-
	Total	26	100.0%	-
Natural Gas	Early	4	9.3%	(197)
	Late	6	14.0%	94
	On time	16	37.2%	0
	Cancelled	5	11.6%	-
	Pending	12	27.9%	-
	Total	43	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
	Total	10	100.0%	-
Oil	Early	3	5.8%	(218)
	Late	7	13.5%	188
	On time	24	46.2%	0
	Cancelled	3	5.8%	(36)
	Pending	15	28.8%	-
	Total	52	100.0%	-
Solar	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	1	1.9%	-
	Total	1	1.9%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	100.0%	-
Storage	Early	3	33.3%	-
	Late	0	0.0%	-
	On time	6	66.7%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	9	100.0%	-

Part V Reliability Service (RMR)

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[170] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff, and the PJM market design has important distinguishing features relative to other regions where arrangements referred to as RMR are used. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. The current capacity market design fails to include transmission constraints inside LDAs with the result that units needed for reliability do not clear in capacity auctions and that prices are suppressed and an RMR is then required. The current approach does not adequately look forward and attempt to address foreseeable unit retirements, whether for economic or regulatory reasons. The result is the wrong price signal for either investing in the existing resource or investing in new resources to provide locational reliability. The answer is not to artificially increase prices during the RMR while the transmission alternative is under construction but to provide an actionable price signal in advance of retirement as a signal to new generation to enter and compete with the transmission solution. It is essential that the deactivation provisions of the tariff be evaluated and modified, both to provide rules that better anticipate deactivations in the markets and rules that reasonably compensate Part V reliability service if it is still needed. Recent changes to the rules fail to address these issues.[171] It is also essential that queue processes that effectively prevent competition from new generation to replace the old generation be modified.

To improve coordination of deactivations and PJM transmission system planning, the MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning which means recognizing transmission constraints inside LDAs when they create reliability issues. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. This result indicates a significant market design flaw.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM treats RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times early in the process when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part, and there is enough time to permit such new entry. There are times later in the process when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete or when there is not enough time to permit such new entry. The relevant rules can and should be changed.

The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[172] It is essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. While not all retirements are completely foreseeable, improvement is needed in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement.

170 OATT Part V §114.

171 See Deactivation Enchancements Senior Task Force (DESTF), which can be accessed at: <https://www.pjm.com/committees-and-groups/task-forces/destf>.

172 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

The actual implementation of Part V of the tariff has resulted in overpayment of the RMR resources. It is essential that the compensation provisions of Part V of the tariff be modified to ensure payment of all but only the actual costs incurred by the generation owner to provide the service, plus an incentive. Generators operating in competitive markets should be required, as an obligation of receiving interconnection service and having the ability to participate in competitive markets, to provide service under Part V on an incremental cost plus incentive basis when they are needed for reliability.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[173] If the MMU determines that expected revenues exceed avoidable costs and therefore that the deactivation is not economic, the MMU will inform the unit owner that there is a market power issue. The MMU has no authority to prevent the retirement. The MMU can pursue the matter at FERC. Part V status by itself creates market power for the retiring resource. The owners of Part V resources have threatened to shut down the resources and put the grid at risk if they do not receive their requested level of Part V payments. Such exercises of market power have been effective in increasing payments to Part V units during the settlement proceedings that have resolved all Part V filings, generally on a black box basis.

PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[174] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service for a defined period.[175] The PJM market rules do not require an owner to remain in service, but owners must provide advance notice of a proposed deactivation although the advance notice can be too short to permit new generation to enter (See Table 5-29).[176] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[177] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[178]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[179] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit." [180] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[181] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[182] Project investment is capped at $2 million, above which FERC approval is required.[183] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[184]

The DACR is unnecessarily prescriptive about the nature of the incremental costs needed to provide service, includes unsupported escalation to extremely high incentive rates, and unnecessarily caps incremental investment at an arbitrary level.

Table 5-32 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022, and is expected to end on February 24, 2025.[185] Only two of nine owners have used the deactivation avoidable cost rate approach. The other seven owners used the cost of service recovery rate. For units using the cost of service recovery rate option, revenues have averaged about 3.8 times the corresponding market

173 OATT § 113.2; OATT Attachment M § IV.1.
174 OATT § 113.2.
175 *Id.*
176 OATT § 113.1.
177 OATT Attachment DD § 6.6(g).
178 *Id.*
179 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
180 OATT § 115.
181 *Id.*
182 OATT § 118.
183 OATT §§ 115, 117.
184 OATT § 119.
185 See PJM, "Informational Filing Regarding Formal Notice of Termination of Reliability Must-Run Service," Docket Nos. ER22-2539-000 and ER23-2688-000 (December 23, 2024).

price of capacity while for units using the deactivation avoidable cost rate, revenues have averaged about 1.6 times the corresponding market price of capacity.[186]

Table 5-32 Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Brandon Shores 1	Talen Energy Corporation	Coal	635.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Brandon Shores 2	Talen Energy Corporation	Coal	638.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Wagner 3	Talen Energy Corporation	Coal	305.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Wagner 4	Talen Energy Corporation	Oil	397.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	24-Feb-25
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Table 5-33 Part V reliability service cost summary[187] [188]

		Initial Filing		Actual		Weighted Average
Unit Names	Owner	Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	RPM Clearing Price ($ per MW-day)
Brandon Shores 1	Talen Energy Corporation	$327,039,342	$393.45	NA	NA	$296.56
Brandon Shores 2	Talen Energy Corporation	$328,584,409	$393.45	NA	NA	$296.56
Wagner 3	Talen Energy Corporation	$64,791,528	$162.29	NA	NA	$296.56
Wagner 4	Talen Energy Corporation	$84,335,202	$162.29	NA	NA	$296.56
Indian River 4	NRG Power Marketing LLC	$357,065,662	$871.76	$167,337,698	$431.89	$54.04
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover sunk costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in

186 The final rate for the Indian River 4 has not been established. The final rate could be lower or higher. The rate in the table is the actual cost to date of the RMR service. The final rates for Brandon Shores and Wagner have not been established. RMR service for these plants has not started.
187 Actual cost data includes RMR charges through December 31, 2024.
188 The actual cost data for Indian River 4 include a refund of the difference between the filed rate that was collected pending resolution and the RMR draft settlement amount.

service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses without verification of actual expenses. Despite the asserted reliance on traditional cost of service ratemaking principles, in practice generators seek approval of high rates that have weak or non existent support in law and fact relative to what has been traditionally required to justify of cost of service rates. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[189] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[190] [191] In another case, the filing ignored evidence of actual book value based on market purchase of the asset.[192] The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM. The requested costs are generally not subject to review, audit and verification.

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service which have generally been set through settlements.

This reliability service should be provided to PJM customers at reasonable rates, which reflect the relatively low risk nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends elimination of both the cost of service recovery rate in OATT Section 119 and the deactivation avoidable cost rate in Part V, and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-34 shows the capacity factors by unit type for 2023 and 2024. In 2024, nuclear units had a capacity factor of 95.1 percent, compared to 95.7 percent in 2023; combined cycle units had a capacity factor of 66.0 percent in 2024, compared to a capacity factor of 63.7 percent in 2023; coal units had a capacity factor of 36.1 percent in 2024, compared to a capacity factor of 30.3 percent in 2023.

189 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
190 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16-21.
191 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022).
192 See Brandon Shores, H.A. Wagner, Docket No. ER24-1787-000, et al. (April 18, 2024); Comments of the Independent Market Monitor for PJM in Opposition to Settlement, Docket No. ER24-1787-000, et al. (February 18, 2025).

Table 5-34 Capacity factor (By unit type (GWh)): 2023 and 2024[193 194 195]

	2023		2024		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Capacity Factor
Battery	28.3	1.1%	51.8	1.8%	0.7%
Combined Cycle	326,709.1	63.7%	334,577.3	66.0%	2.2%
Single Fuel	282,435.2	68.7%	287,727.8	70.8%	2.1%
Dual Fuel	44,273.9	43.6%	46,849.5	46.4%	2.8%
Combustion Turbine	21,483.0	8.2%	22,750.9	9.0%	0.8%
Single Fuel	15,294.4	8.8%	14,301.1	8.2%	(0.6%)
Dual Fuel	6,188.6	7.1%	8,449.9	10.9%	3.8%
Diesel	459.7	14.3%	324.6	12.5%	(1.9%)
Single Fuel	442.1	15.5%	298.4	12.9%	(2.6%)
Dual Fuel	17.6	4.8%	26.2	8.7%	3.8%
Diesel (Landfill gas)	1,028.6	51.6%	901.9	49.6%	(2.1%)
Fuel Cell	197.9	82.5%	215.2	89.5%	7.0%
Nuclear	273,488.6	95.7%	272,744.4	95.1%	(0.5%)
Pumped Storage Hydro	7,644.4	16.1%	8,143.8	17.1%	1.0%
Run of River Hydro	7,844.3	43.6%	7,857.6	43.5%	(0.0%)
Solar	10,965.7	19.3%	17,261.3	19.1%	(0.2%)
Steam	131,327.8	6.1%	137,407.9	8.6%	2.5%
Biomass	5,281.9	66.4%	4,993.7	64.8%	(1.6%)
Coal	115,772.9	30.3%	119,918.0	36.1%	5.8%
Single Fuel	115,725.6	33.7%	119,918.0	36.7%	3.0%
Dual Fuel	47.3	14.3%	0.0	0.0%	(14.3%)
Natural Gas	9,293.0	43.2%	11,341.0	46.0%	2.8%
Single Fuel	479.3	52.9%	519.9	54.0%	1.1%
Dual Fuel	8,813.6	22.3%	10,821.1	27.3%	5.0%
Oil	980.1	2.5%	1,155.2	4.1%	1.6%
Wind	28,787.6	7.4%	31,383.8	16.1%	8.7%
Total	809,965.1	45.6%	833,620.5	48.3%	2.6%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[196] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[197] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-7, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-7, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2024, the period runs from Monday, June 10 until Friday, September 6. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-10.

193 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
194 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
195 Hours in which batteries have net negative generation do not count toward their runtime.
196 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 45 (Nov. 21, 2024).
197 OATT, Attachment K (Appendix) § 1.9.3 (b).

Figure 5-7 Outages (MW): 2012 through 2024

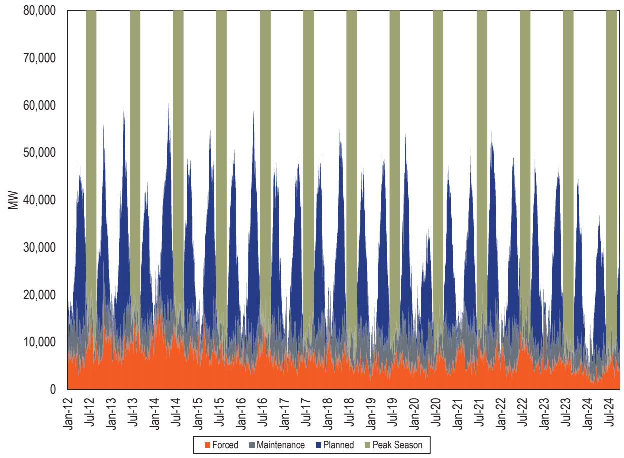
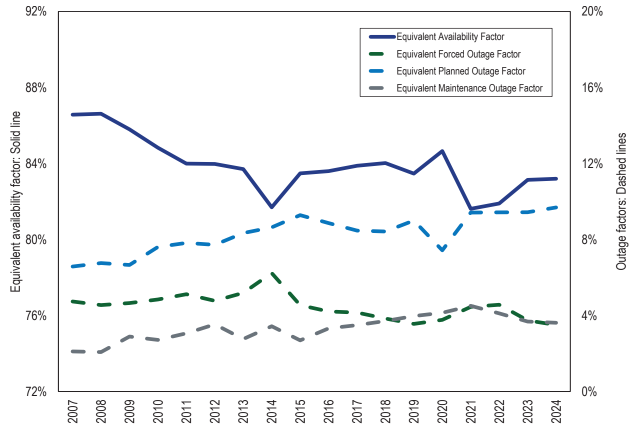


Figure 5-8 Equivalent outage and availability factors: 2007 to 2024



In 2024, forced outages were 13.0 percent lower, planned outages were 2.9 percent lower, and maintenance outages were 9.1 percent lower than in 2023.

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-8. Metrics by unit type are shown in Table 5-35.

Table 5-35 EFOF, EPOF, EMOF and EAF by unit type: 2007 to 2024

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7%	8%	3%	81%	2%	6%	2%	90%	5%	3%	3%	90%	10%	1%	2%	87%
2008	7%	7%	2%	83%	2%	6%	2%	90%	3%	5%	2%	90%	9%	1%	1%	88%
2009	7%	8%	4%	81%	3%	7%	3%	87%	2%	3%	3%	93%	7%	1%	1%	92%
2010	8%	9%	4%	78%	3%	9%	2%	86%	2%	3%	2%	93%	5%	0%	1%	94%
2011	8%	9%	5%	78%	3%	9%	2%	86%	2%	4%	2%	92%	3%	0%	2%	95%
2012	8%	9%	6%	77%	3%	8%	2%	87%	3%	3%	2%	92%	4%	1%	2%	93%
2013	9%	11%	5%	76%	2%	9%	2%	87%	5%	5%	1%	89%	6%	0%	1%	92%
2014	10%	10%	5%	75%	2%	10%	3%	85%	7%	4%	2%	87%	14%	0%	2%	83%
2015	8%	11%	4%	78%	2%	11%	2%	85%	3%	5%	2%	90%	8%	0%	3%	89%
2016	8%	10%	6%	77%	3%	10%	2%	85%	2%	6%	2%	90%	5%	0%	3%	92%
2017	9%	11%	7%	73%	2%	10%	2%	86%	1%	6%	2%	91%	6%	0%	2%	92%
2018	9%	12%	7%	73%	1%	9%	1%	88%	2%	5%	2%	91%	6%	1%	3%	89%
2019	8%	11%	8%	74%	2%	11%	2%	85%	2%	7%	2%	90%	7%	1%	3%	89%
2020	5%	10%	9%	76%	4%	8%	2%	87%	2%	6%	2%	90%	7%	0%	3%	90%
2021	8%	15%	9%	67%	3%	10%	2%	85%	3%	6%	3%	88%	9%	0%	4%	86%
2022	9%	14%	9%	68%	3%	10%	2%	85%	3%	7%	2%	88%	11%	0%	4%	84%
2023	8%	14%	7%	72%	3%	12%	2%	83%	2%	7%	2%	89%	12%	0%	4%	84%
2024	7%	14%	8%	71%	3%	11%	1%	84%	3%	6%	2%	89%	9%	1%	2%	88%

	Hydroelectric				Nuclear				Other				Total			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1%	7%	1%	90%	1%	5%	0%	93%	5%	7%	3%	84%	5%	7%	2%	87%
2008	1%	8%	2%	88%	2%	5%	1%	92%	4%	11%	3%	81%	5%	7%	2%	87%
2009	2%	9%	2%	87%	4%	5%	1%	90%	3%	8%	5%	84%	5%	7%	3%	86%
2010	1%	8%	2%	89%	2%	6%	0%	92%	4%	11%	4%	82%	5%	8%	3%	85%
2011	2%	12%	2%	84%	3%	5%	1%	91%	5%	11%	3%	81%	5%	8%	3%	84%
2012	3%	6%	2%	89%	2%	6%	1%	91%	5%	13%	4%	79%	5%	8%	4%	84%
2013	2%	8%	2%	87%	1%	6%	1%	93%	6%	11%	3%	79%	5%	8%	3%	84%
2014	3%	10%	3%	85%	2%	5%	1%	92%	7%	17%	5%	72%	6%	9%	3%	82%
2015	4%	10%	2%	85%	1%	5%	1%	92%	6%	18%	4%	72%	5%	9%	3%	83%
2016	3%	8%	3%	86%	2%	5%	1%	92%	5%	17%	5%	74%	4%	9%	3%	84%
2017	2%	6%	3%	89%	0%	5%	1%	94%	5%	10%	6%	79%	4%	8%	3%	84%
2018	2%	8%	3%	87%	1%	5%	1%	94%	4%	9%	9%	78%	4%	8%	4%	84%
2019	1%	7%	4%	88%	1%	5%	1%	93%	4%	14%	7%	75%	4%	9%	4%	83%
2020	4%	7%	3%	86%	1%	5%	1%	93%	9%	8%	5%	77%	4%	7%	4%	85%
2021	8%	8%	3%	81%	1%	5%	1%	93%	7%	9%	6%	78%	4%	9%	5%	82%
2022	2%	9%	3%	86%	1%	5%	1%	93%	6%	10%	6%	78%	5%	9%	4%	82%
2023	3%	15%	4%	78%	1%	4%	2%	93%	5%	9%	7%	79%	4%	9%	4%	83%
2024	3%	16%	4%	76%	1%	5%	2%	92%	5%	11%	3%	81%	4%	10%	4%	83%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[198] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in 2024 was 5.2 percent, a decrease from 5.5 percent in 2023. Figure 5-9 shows the average EFORd since 1999 for all units in PJM.[199]

198 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.

199 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2024 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Figure 5-9 Equivalent demand forced outage rates (EFORd): 1999 to 2024

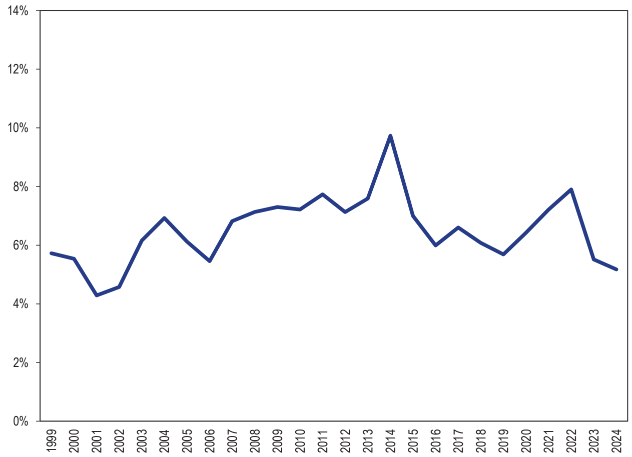


Table 5-36 shows the class average EFORd by unit type.

Table 5-36 EFORd by unit type: 2007 to 2024

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coal	8.3%	8.6%	8.5%	9.8%	10.9%	10.5%	11.1%	12.9%	9.7%	9.7%	11.8%	11.4%	10.7%	8.7%	11.8%	12.9%	11.5%	9.4%
Combined Cycle	4.1%	4.3%	5.2%	4.3%	3.5%	3.5%	2.1%	4.0%	2.3%	3.4%	2.8%	1.9%	2.7%	4.2%	3.5%	4.6%	3.5%	3.5%
Combustion Turbine	12.1%	12.1%	10.0%	10.1%	8.7%	7.9%	10.9%	16.7%	9.0%	5.5%	5.3%	6.3%	5.5%	4.5%	5.5%	8.9%	4.9%	6.1%
Diesel	12.0%	10.5%	9.5%	6.4%	9.3%	4.9%	6.7%	15.3%	9.1%	6.9%	6.9%	6.8%	7.7%	7.8%	11.9%	14.5%	14.0%	12.1%
Hydroelectric	2.0%	2.0%	3.3%	1.2%	2.8%	4.5%	3.7%	4.0%	5.5%	3.8%	3.1%	3.2%	1.9%	5.4%	10.6%	3.3%	4.6%	4.5%
Nuclear	1.4%	2.0%	4.3%	2.6%	2.9%	1.8%	1.0%	1.8%	1.5%	1.8%	0.5%	0.8%	0.6%	1.4%	1.1%	1.2%	0.9%	0.9%
Other	9.4%	9.8%	8.4%	7.4%	9.7%	8.7%	10.9%	13.3%	13.0%	9.2%	14.0%	9.5%	9.7%	20.4%	18.3%	17.4%	6.3%	7.9%
Total	6.8%	7.1%	7.3%	7.2%	7.7%	7.1%	7.6%	9.7%	7.0%	6.0%	6.6%	6.1%	5.7%	6.4%	7.2%	7.9%	5.5%	5.2%

EFORd vs EAF

EFORd is not an adequate measure of unit availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[200] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

200 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

Table 5-37 shows the differences between EFORd and EAF by unit type.

Table 5-37 EFORd and EAF by unit type: 2012 to 2024

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	10.5%	22.9%	3.5%	13.2%	7.9%	7.9%	4.9%	7.1%	4.5%	10.9%	1.8%	8.9%	8.7%	21.2%	7.1%	16.0%
2013	11.1%	23.6%	2.1%	13.1%	10.9%	11.4%	6.7%	7.8%	3.7%	12.6%	1.0%	7.2%	10.9%	20.5%	7.6%	16.3%
2014	12.9%	25.4%	4.0%	15.0%	16.7%	12.7%	15.3%	16.7%	4.0%	15.4%	1.8%	8.0%	13.3%	28.4%	9.7%	18.3%
2015	9.7%	22.5%	2.3%	14.5%	9.0%	9.7%	9.1%	10.9%	5.5%	15.4%	1.5%	7.9%	13.0%	28.4%	7.0%	16.5%
2016	9.7%	23.2%	3.4%	14.7%	5.5%	10.4%	6.9%	8.2%	3.8%	13.8%	1.8%	8.2%	9.2%	25.8%	6.0%	16.4%
2017	11.8%	26.8%	2.8%	13.8%	5.3%	9.3%	6.9%	8.4%	3.1%	11.2%	0.5%	6.3%	14.0%	20.8%	6.6%	16.1%
2018	11.4%	27.3%	1.9%	12.1%	6.3%	9.1%	6.8%	10.6%	3.2%	13.4%	0.8%	6.0%	9.5%	21.5%	6.1%	16.0%
2019	10.7%	26.2%	2.7%	14.7%	5.5%	10.4%	7.7%	11.1%	1.9%	12.4%	0.6%	6.8%	9.7%	24.9%	5.7%	16.5%
2020	8.7%	24.1%	4.2%	13.3%	4.5%	10.1%	7.8%	9.8%	5.4%	13.8%	1.4%	6.8%	20.4%	23.0%	6.4%	15.3%
2021	11.8%	32.5%	3.5%	14.6%	5.5%	12.0%	11.9%	13.7%	10.6%	19.1%	1.1%	6.7%	18.3%	22.3%	7.2%	18.4%
2022	12.9%	31.9%	4.6%	15.4%	8.9%	12.2%	14.5%	15.5%	3.3%	13.6%	1.2%	7.4%	17.4%	22.2%	7.9%	18.1%
2023	11.5%	28.4%	3.5%	16.7%	4.9%	11.0%	14.0%	16.0%	4.6%	21.6%	0.9%	6.5%	6.3%	20.8%	5.5%	16.9%
2024	9.4%	28.9%	3.5%	15.5%	6.1%	11.1%	12.1%	12.3%	4.5%	23.8%	0.9%	7.6%	7.9%	19.1%	5.2%	16.8%
Average	10.9%	26.4%	3.2%	14.4%	7.5%	10.6%	9.6%	11.4%	4.5%	15.2%	1.2%	7.3%	12.2%	23.0%	6.8%	16.7%

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[201] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 3.5 percent in 2024. Table 5-38 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 14.1 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types.

Table 5-38 Contribution to PJM EFOF by unit type by cause: 2024

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	26.1%	4.1%	0.0%	0.0%	0.0%	0.0%	10.2%	14.1%
Unit Testing	3.9%	5.9%	14.5%	26.9%	59.4%	19.9%	20.8%	12.0%
Generator	6.0%	23.2%	1.8%	1.7%	4.3%	0.0%	0.0%	6.8%
Boiler Air and Gas Systems	11.4%	0.8%	0.0%	0.0%	0.0%	0.0%	5.7%	6.1%
Electrical	4.5%	4.4%	15.0%	24.4%	0.1%	0.9%	1.3%	5.4%
Turbine	0.0%	6.8%	19.1%	0.0%	5.7%	0.0%	0.0%	4.2%
Miscellaneous (Generator)	4.5%	4.8%	1.4%	11.9%	0.8%	3.7%	1.3%	3.6%
Controls	2.2%	4.0%	0.3%	5.5%	0.1%	1.7%	9.4%	2.8%
Boiler Tube Fireside Slagging or Fouling	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	2.6%
Miscellaneous (Steam Turbine)	2.3%	1.4%	0.0%	0.0%	0.0%	6.2%	8.9%	2.5%
Miscellaneous (Gas Turbine)	0.0%	4.0%	13.3%	0.0%	0.0%	0.0%	0.0%	2.5%
Feedwater System	3.5%	0.8%	0.0%	0.0%	0.0%	9.4%	0.6%	2.4%
Boiler Piping System	3.5%	3.4%	0.0%	0.0%	0.0%	0.0%	0.3%	2.2%
Auxiliary Systems	1.6%	2.1%	4.7%	0.0%	0.1%	0.0%	3.0%	2.1%
Condensing System	1.1%	0.3%	0.0%	0.0%	0.0%	6.5%	10.3%	2.0%
Circulating Water Systems	2.7%	3.3%	0.0%	0.0%	0.0%	2.7%	0.6%	2.0%
Boiler Fuel Supply from Bunkers to Boiler	3.3%	0.4%	0.0%	0.0%	0.0%	0.0%	1.7%	1.8%
Fuel Quality	0.8%	0.0%	7.5%	2.4%	0.0%	0.0%	1.7%	1.7%
Condensate System	1.7%	1.7%	0.0%	0.0%	0.0%	0.4%	3.4%	1.4%
All Other Causes	15.6%	28.5%	22.5%	27.1%	29.5%	48.8%	20.1%	21.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

201 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EMOF was 3.6 percent in 2024. Table 5-39 shows the causes of EMOF by unit type. Maintenance outages for boiler air and gas systems, 8.1 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although electrical issues were the largest contributors to EMOF for combustion turbines.

Table 5-39 Contribution to EMOF by unit type by cause: 2024

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Air and Gas Systems	12.9%	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	8.1%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	66.2%	0.0%	8.0%
Intermediate Pressure Turbine	12.9%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	7.9%
Boiler Tube Leaks	6.3%	9.0%	0.0%	0.0%	0.0%	0.0%	33.7%	6.4%
Electrical	5.9%	2.4%	11.4%	2.3%	23.8%	1.4%	0.1%	6.2%
Miscellaneous (Balance of Plant)	6.4%	7.0%	8.2%	0.2%	0.3%	0.0%	7.0%	5.5%
Boiler Piping System	7.3%	13.5%	0.0%	0.0%	0.0%	0.0%	0.0%	5.4%
Miscellaneous (Gas Turbine)	0.0%	10.2%	29.7%	0.0%	0.0%	0.0%	0.0%	3.4%
Boiler Overhaul and Inspections	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.1%	3.3%
Turbine	0.0%	2.9%	2.6%	0.0%	42.2%	0.0%	0.0%	2.8%
Circulating Water Systems	4.1%	0.0%	0.0%	0.0%	0.0%	1.2%	0.7%	2.7%
Auxiliary Systems	2.5%	1.5%	11.0%	0.2%	0.0%	0.0%	1.7%	2.7%
Cooling System	3.5%	6.0%	0.0%	0.3%	0.1%	0.0%	0.0%	2.6%
Wet Scrubbers	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%
Miscellaneous (Steam Turbine)	3.3%	2.8%	0.0%	0.0%	0.0%	0.4%	2.1%	2.4%
Boiler Internals and Structures	3.3%	2.7%	0.0%	0.0%	0.0%	0.0%	2.6%	2.4%
Boiler Fuel Supply from Bunkers to Boiler	3.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	2.0%
Valves	1.8%	7.6%	0.0%	0.0%	0.0%	1.5%	0.4%	1.9%
Boiler Tube Fireside Slagging or Fouling	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	1.6%
All Other Causes	15.1%	33.2%	37.0%	96.9%	33.5%	29.3%	41.1%	22.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 9.7 percent in 2024. Table 5-40 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant issues, 23.2 percent of the system EPOF, were the largest single contributor to average system EPOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EPOF for combustion turbines.

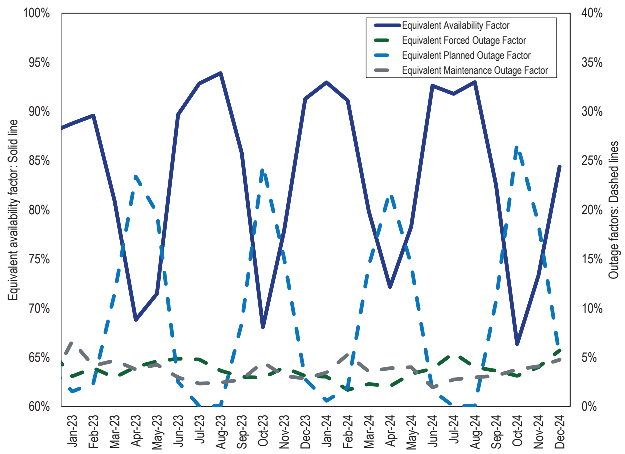
Table 5-40 Contribution to EPOF by unit type and cause: 2024

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Balance of Plant)	37.8%	26.3%	13.2%	2.2%	0.0%	0.0%	28.0%	23.2%
Miscellaneous (Gas Turbine)	0.0%	48.6%	56.4%	0.0%	0.0%	0.0%	0.0%	17.5%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	98.3%	0.0%	12.8%
Boiler Overhaul and Inspections	15.1%	4.8%	0.0%	0.0%	0.0%	0.0%	32.2%	8.8%
Miscellaneous (Steam Turbine)	5.3%	11.3%	0.0%	0.0%	0.0%	0.0%	0.5%	4.4%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	45.3%	0.3%	0.0%	4.2%
Low Pressure Turbine	8.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%
Miscellaneous (Generator)	3.9%	0.1%	3.4%	4.7%	10.2%	0.0%	0.0%	2.8%
Generator	0.0%	0.8%	2.1%	0.3%	18.8%	0.0%	1.4%	2.3%
Wet Scrubbers	6.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%
Valves	4.2%	0.3%	0.0%	0.0%	0.0%	0.0%	3.9%	1.9%
Turbine	0.0%	2.0%	0.4%	0.0%	12.6%	0.0%	0.0%	1.7%
Miscellaneous (Boiler)	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	19.9%	1.4%
Boiler Air and Gas Systems	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	4.9%	1.2%
NOx Reduction Systems	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%
Stack Emission	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%
Boiler Internals and Structures	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Boiler Control Systems	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%
Boiler Piping System	1.2%	0.6%	0.0%	0.0%	0.0%	0.0%	3.4%	0.8%
All Other Causes	4.5%	4.1%	24.5%	92.8%	13.1%	1.4%	5.8%	7.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-10.

Figure 5-10 Monthly generator performance factors: 2023 through 2024



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[202] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[203] Wind and solar resources do not perform verification tests to prove capability.[204]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[205]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[206] Nine resources were assessed for generation resource rating test failure charges in 2024.

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[207]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by power meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have

202 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 59 (June 27, 2024).
203 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 59 (June 27, 2024).
204 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 59 (June 27, 2024).
205 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.
206 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 59 (June 27, 2024).
207 OATT, Attachment DD (Reliability Pricing Model) § 7.

the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[208] In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM total nonperformance charges were approximately $1.796 billion, reduced to $1.226 billion in a settlement agreement.[209] There were no such charges assessed in 2023 or 2024.

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[210] [211] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[212] [213] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 64 resources were assessed for deficiency charges in 2022, 175 resources were assessed for deficiency charges in 2023, and 434 resources were assessed for deficiency charges in 2024.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014. Table 5-41 shows that from 2014 through 2024, of all the changes in outage status, 96.2 percent of the outages and 86.6 percent of the outage MWh were changed from either planned or maintenance to forced outage status. Of those changes to forced outage status, 41.4 percent of the outages and 84.1 percent of the MWh were for coal and hydro plants.

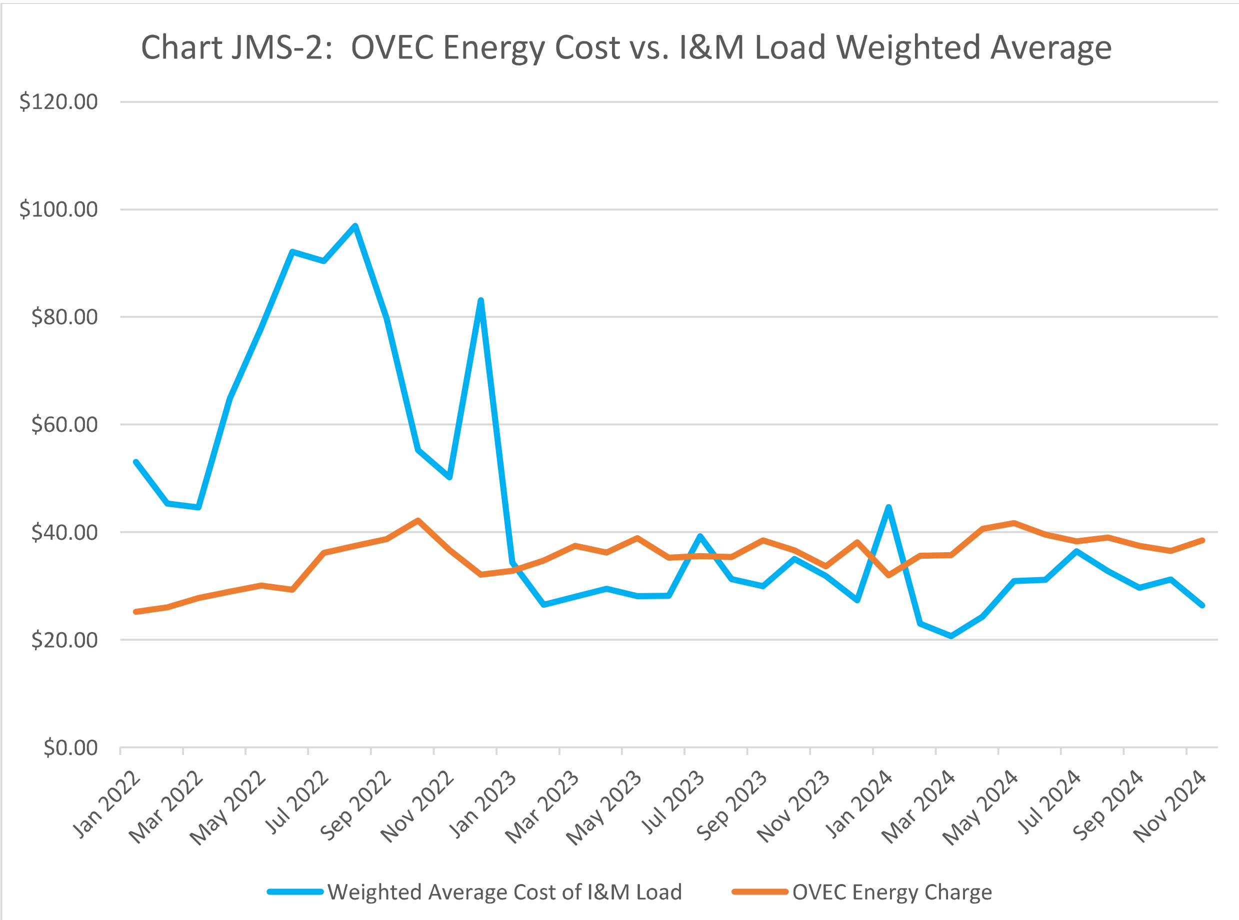
208 OATT, Attachment DD (Reliability Pricing Model) § 10A.
209 See Settlement Agreement, Docket No. ER23-2975-000 (September 29, 2023), which can be accessed at: <https://pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx>.
210 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 19 (June27, 2024).
211 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
212 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 59 (June 27, 2024).
213 OATT, Attachment DD (Reliability Pricing Model) § 8.

Table 5-41 Changed outages by unit type: 2014 through 2024[214]

Unit Type	Year	Forced to Maintenance No. Outages	Forced to Maintenance MWh	Forced to Planned No. Outages	Forced to Planned MWh	Maintenance or Planned to Forced No. Outages	Maintenance or Planned to Forced MWh
Coal	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	170,807
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	1	13,211	0	NA	0	NA
	2024	1	18,908	0	NA	0	NA
	Total	14	805,898	0	NA	233	5,736,526
Combined Cycle	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022	0	NA	1	3,817	2	208
	2023	0	NA	0	NA	0	NA
	2024	3	2,625	0	NA	0	NA
	Total	10	37,315	11	373,648	89	743,650
Combustion Turbine	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023	0	NA	0	NA	4	270,336
	2024	0	NA	0	NA	3	174,191
	Total	9	26,990	6	57,104	199	736,597
Diesel	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	27,059
	2022	4	5,492	0	NA	10	305
	2023	0	NA	0	NA	0	NA
	2024	0	NA	0	NA	0	NA
	Total	28	6,147	0	NA	1,300	82,408
Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	281,976
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023	0	NA	0	NA	9	196,512
	2024	0	NA	0	NA	0	NA
	Total	12	135,420	0	NA	922	5,669,622
Nuclear	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	0	NA	0	NA	0	NA
	2024	0	NA	2	168,615	0	NA
	Total	0	NA	4	346,807	2	22,903
Other	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	2	17,023	0	NA	0	NA
	2024	0	NA	0	NA	0	NA
	Total	14	269,134	2	37,294	47	566,132
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,324,165
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	624,398
	2021	3	137	7	303,061	41	315,679
	2022	4	5,492	1	3,817	18	30,896
	2023	3	30,234	0	NA	13	466,848
	2024	4	21,533	2	168,615	3	174,191
	Total	87	1,280,903	23	814,853	2792	13,557,838

214 Year describes the year in which the outage started and not the year in which the outage designation was changed.

contrast, OVEC energy has continued to hold steady for the entire period. As shown in Chart JMS-2 below, OVEC energy has been much less volatile than the load weighted average price paid for I&M load.



Q. Did the energy revenues generated by the sale of the Company's share of OVEC energy produce enough revenues to offset the total amount billed under the ICPA?

A. No. Market prices during 2024 remained low and, as a result, the energy revenues earned did not surpass the total energy billings to the Company.

Q. Is this an indication that the ICPA is an uneconomic energy resource?

Gross Avoidable Costs for Existing Generation

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TABLE OF CONTENTS

Executive Summary

Starting with the 2022/23 Delivery Year, PJM Interconnection, L.L.C. (PJM) is required under the Open Access Transmission Tariff (OATT or tariff) to update Default Gross Avoidable Cost Rates (ACRs) every four years.[1] This study informs PJM's filing by developing updated gross cost estimates for various existing generation types.

PJM uses Default Gross ACRs (minus unit-specific net energy and ancillary services (E&AS) revenues) to determine default offer thresholds for mitigating market power in its capacity market. For several years, the Default Gross ACRs were used only for mitigating so-called "buyer-side" market power; capacity resources that were subject to the Minimum Offer Price Rule (MOPR) were subject to default offer floors and could offer at lower prices only if accepted through a unit-specific review of actual costs.[2] However, in March 2021, the Federal Energy Regulatory Commission (FERC) ordered PJM to expand the application of Default ACRs to its mitigation of supplier market power, after finding that the existing offer caps were excessive.[3] Any resources subject to Market Seller Offer Caps (MSOCs) could now offer above the default ACRs only by demonstrating higher costs through unit-specific reviews. Thus, PJM's updated Default Gross ACRs will be used for mitigating supplier market power (via MSOC) as well as for MOPR purposes in PJM's Base Residual Auctions for 2026/27 and the following three delivery years.

To conduct this update of the Default ACRs, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the gross avoidable costs for several types of existing generation. We have done so based on bottom-up analysis of costs for representative plants, drawing on data and the combined experience of Brattle and S&L. We also solicited and incorporated stakeholder input through three rounds of presentations before the Market Implementation Committee (MIC) between October and December.

Our approach recognizes that existing generation resources vary considerably in their characteristics and costs, both across resource types and even within each type. This variability

[1] PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14(h-2)(3)(B).

[2] See Minimum Offer Price Rule (MOPR)—Attachment DD § 5.14(h-2).

[3] See Market Seller Offer Cap (MSOC)—Attachment DD § 6.4.

must be considered in developing coherent "types" and in developing default offer thresholds for each, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

To inform PJM's determination of a single Default Gross ACR for each resource type, we reviewed the range of characteristics of resources in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We identified for each resource type the characteristics of a "representative plant" that is widely representative of most of the fleet and reflects the median MW in terms of cost structure. We also identified the characteristics for "representative low-cost" and "representative high-cost" plants to inform the range of costs PJM may see for each type of existing generation resource.

Given the assumed characteristics, we then estimated the avoidable gross costs of the representative plants to inform PJM's filing of Default Gross ACRs. The cost estimates are based on S&L analysis of FERC Form 1 data and the Nuclear Energy Institute's (NEI's) "Nuclear Costs in Context" study and its own proprietary database, and Brattle analysis.

We also provide estimates for the Variable Operation and Maintenance (VOM) costs as a benchmark to inform PJM's E&AS net revenue analysis when determining Net ACRs. The classification of costs categories as gross versus variable align with PJM's current market rules concerning the costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the E&AS revenue component of Net ACRs). Accordingly, the costs of major maintenance and overhauls directly related to the production of electricity are included in variable costs as a "maintenance adder."

Table ES-1 below shows the resulting gross costs for each existing generation resource type, expressed in 2022 dollars per-megawatt (MW) of nameplate capacity. Variable costs are presented separately, within the body of this report. Note that throughout this report, our results are presented as "gross costs" rather than "Gross ACRs" because the formal term reflects a tariff rate filed by PJM and approved by FERC, and our study only informs those rates.

TABLE ES-1: EXISTING GENERATION GROSS COSTS
(IN 2022 DOLLARS PER NAMEPLATE MW PER DAY)

Resource Type	Representative Plant $/MW-day
Multi-unit Nuclear	**$537**
Single-unit Nuclear	**$591**
Coal	**$94**
Natural Gas CC	**$113**
Simple Cycle CT	**$52**
ST O&G	**$64**
Onshore Wind	**$147**
Solar PV	**$70**

I. Introduction

A. Purpose of ACRs and this Analysis

In the presence of structural market power in capacity markets, PJM as market operator needs to be able to mitigate offers outside of reasonable bounds of competitive levels. Concerns surround both supplier market power and buyer market power. Supplier market power is deemed a threat where jointly-pivotal market sellers fail the Three Pivotal Supplier ("TPS") test, which all typically do.[4] Under such circumstances, resource offers would be subject to Market Seller Offer Caps (MSOC). Buyer market power—in the form of resources being offered at artificially lower prices—is deemed a concern under special circumstances and applicable resources would be subject to the Minimum Offer Price Rule (MOPR). MOPR applicability has recently been narrowed after much litigation.[5]

PJM will approach both instances by setting default offer thresholds for various resource types, such that higher-priced offers on MSOC-applicable resources could trigger a unit-specific review to consider setting a higher unit-specific MSOC; lower-priced offers on MOPR-applicable resources could trigger a unit-specific review to set a lower unit-specific MOPR. Default thresholds will be determined by a generic resource type-specific Gross Avoidable Cost Rate (ACR) minus resource-specific net revenues from energy and ancillary services markets (net E&AS offset).

Until recently, MSOCs were set uniformly across all existing resources, given by the Net Cost of New Entry (Net CONE) times an average "balancing ratio" of 85% based on an assumed number of Performance Assessment Intervals (PAIs). However, in March 2021, the Federal Energy Regulatory Commission (FERC) found the MSOCs to be unjust and unreasonable.[6] FERC found those rates to be too high, due to an unrealistically high estimate of the number of expected PAIs. FERC ordered PJM to use more specific Avoidable Cost Rates, as it uses for MOPR, and as it had used for MSOC purposes prior to the implementation of Capacity Performance in 2016.

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4 PJM, Market Seller Offer Cap (MSOC) Reform, February 28, 2022.

5 Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000, September 29, 2021.

6 Federal Energy Regulatory Commission, Order Granting Complaints and Ordering Additional Briefing, Docket Nos. EL 19-47-000 and EL 19-63-000, March 18, 2021.

Thus, this updated ACR study will be used for both purposes, in fulfillment of PJM's requirement to periodically update its Default Avoidable Cost Rates (ACRs) every four years.[7] The last such study was conducted by us in 2020, but future studies will be conducted every four years.

For this study, PJM requested that we estimate Gross Costs for existing generation resource types. The types would be defined to span most of the PJM fleet, where each type includes similar resources with similar cost structures; types would not be defined for resource classes that exhibit highly idiosyncratic and varying avoidable costs. For each type, we were asked to develop bottom-up cost estimates of the gross fixed costs for a "representative" plant, For informational purposes we also provided a "representative low" and "representative high" for lower and higher-cost sub-groups within each type. Additionally, PJM requested that we determine the Variable Operation and Maintenance (VOM) costs for each resource type for informational purposes to aide PJM in determining E&AS revenues.

As PJM applies the study results to determine default offer thresholds, it will need to balance the need to mitigate the exercise of market power against the administrative burden and risks of over-mitigation. Over-mitigation is possible due to information asymmetries between PJM and capacity sellers, even in unit-specific reviews. That could result, for example, in a resource's MSOC being set below its true competitive costs—which could discourage participation in the market. Over-mitigation can be avoided in part by setting default MSOCs reasonably high so that many resources would not need a unit-specific review to justify higher offers; and by setting default MOPRs reasonably low for symmetrical reasons.

B. Analytical Approach

To calculate the gross default costs we first identified types that span most of the installed capacity in the PJM footprint and have sufficiently little variation of gross fixed costs within the type. We then analyzed the fleet and identified defining characteristics of the median plant by capacity; and then calculated the gross costs that would be avoided if such a plant retired. The calculations are consistent with PJM's tariff for the scope of costs allowable in Gross ACRs.

For the definition of types, we received an initial list from PJM that was based on the previously identified types from the 2020 Gross ACR study. These types were chosen to span a large

[7] PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14(h-2)(3)(B).

portion of the overall PJM fleet and such that each type is coherent and has common cost characteristics within it. We then iterated upon the defined types with PJM and market stakeholders and included one additional type due to stakeholder feedback. A small remaining portion of the fleet that we did not characterize as "types" with a Default Gross ACR had more idiosyncratic cost characteristics among individual plants (e.g., due to older, non-standard technology) so did not lend themselves well to defining a standardized estimate of costs; absent a Gross ACR, these plants will have to rely on unit-specific reviews for nonzero capacity offers.

For each defined resource type, we identified the characteristics of a "representative plant" that is widely representative of the individual plants within that type. The "representative plant" standard that we agreed on with PJM staff and reviewed with stakeholders was a median for the population of PJM plants in each type, with the median being defined on a capacity (MW) basis. Since it would have been impractical to develop cost estimates for every plant in the fleet, we instead identified the median plant as one with median values of the main cost drivers: (1) the unit size; (2) the plant age and technology vintage; (3) the plant location in PJM; and (4) the configuration of the units, including pollution controls. We then estimated the costs for such a plant as described below.

While we agreed with PJM and stakeholders that the representative plant would be used to determine the Default Gross ACRs, we also sought to inform the range of costs PJM might see for each type. We thus defined a "representative high-cost" and a "representative low-cost" plant for each type, considering the range of characteristics and especially clusters thereof. This was unnecessary, however, for single-unit nuclear plants since the population consists of only two plants.

Given the assumed representative characteristics, we then estimated the costs of the representative plants to inform the gross costs, as well as the variable O&M costs to inform PJM's net E&AS analysis. Gross costs reflect the fixed costs of operating an existing generation resource for an additional year that could be avoided if the plant retires.[8] Our cost estimates for most types of thermal plants are based on S&L's regression analyses of FERC Form 1 filings for plants with characteristics similar to the representative plants for each resource type, benchmarked and adjusted using confidential cost estimates from S&L's project database. For nuclear plants, where FERC Form 1 submissions were deemed inconsistent, we relied on NEI's

[8] Given the very limited prevalence of "mothballing," meaning a unit that does not operate for the Delivery Year but is maintained in a state such that it may be brought back into service in a future year, we only consider the costs that are avoidable if a unit retires.

latest "Nuclear Costs in Context" study, with adjustments to reflect the representative plant. For wind and solar plants, for which FERC Form 1 data is sparse, we relied on S&L's extensive project database.

For most types, property taxes and insurance constitute a relatively small fraction of total cost, but they are less straightforward to quantify uniformly, and we have refined our approach since our 2020 study and over the course of this study based on stakeholder feedback. Our approach to estimating these costs varies by resource type given data availability, and is described under each type presented below.

One aspect of this study that required careful consideration was to distinguish which costs to include in the gross costs and which to consider as variable costs. Only the gross costs would determine resource types' Default Gross ACRs, while variable costs would presumably be accounted for in resources' Default Net ACRs for capacity offer mitigation purposes if generators include them in their cost-based energy offers. To avoid double counting any such costs, it is important to categorize these costs consistently with PJM's rules regarding energy market offers. We followed PJM guidance regarding its tariff and operating agreements.[9] Among other cost categories, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder that includes activities such as repair, replacement, and major inspection.[10] Therefore, consistent with tariff, our estimated gross costs include Fixed Capital Costs and Fixed Operation & Maintenance (FOM) costs but not major maintenance costs for systems directly related to electric production. In the case of nuclear plants, however, we provide an indicative estimate of the gross costs with major maintenance included for informational purposes in the hypothetical case if PJM were to determine that major maintenance should be included in the Gross ACR

9 PJM staff reviewed the specifications in their tariff and operating agreements, and provided guidelines to follow based on their interpretation. The PJM Open Access Transmission Tariff (OATT) Attachment DD section 6.8(c) specifies that "[v]ariable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate." Section 6.8 also lists eleven components of Avoidable Cost Rates. The PJM Operating Agreement Schedule 2 further specifies the expenses allowed to be included in the maintenance adder as a variable cost as part of energy offers, rather than in the Gross ACR: "Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses." Schedule 2 states that "preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment" cannot be included in cost-based energy offers, and thus are included in the Gross ACR. We understand that PJM interprets this to mean that all maintenance costs for systems directly related to electric production can be included in the operating costs maintenance adder for cost-based energy offers, and thus are excluded from the Avoidable Cost Rates. See PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 6 Market Power Mitigation, Section 6.8(c).

10 PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

and adapts its tariff accordingly. For the remainder of plant types, given PJM's guidance, we identify the types of maintenance costs included in the gross costs and those included in the variable cost maintenance adder, and estimate the costs of each accordingly, as reported below.

II. Selection of Plant Types within PJM Fleet

Based on PJM input, the approach described above, and stakeholder feedback, we defined the following resource types for estimating gross costs:

- Multi-unit nuclear
- Single-unit nuclear
- Coal
- Natural gas-fired combined-cycle turbines (NG CC)
- Simple-cycle combustion turbines (Simple Cycle CT), previously limited to natural gas combustion turbines
- Oil and gas-fired steam turbines (ST O&G), new type based on stakeholder feedback
- Onshore wind
- Large-scale (>1 MW) solar photovoltaic plants (Solar PV)

These types are similar to those in the 2020 ACR study, but expanded based on stakeholder feedback. We added an oil and gas-fired steam turbine type and amplified the simple-cycle combustion turbine type to include oil peaker plants as well as gas plants compared to the 2020 ACR determination.[11] Table 1 shows a breakdown of the current capacity of the PJM fleet. The chosen resource types combined cover about 94% of the entire PJM fleet.

[11] Newell, et al., Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency, March 17, 2020 ("2020 Gross ACR Study").

TABLE 1: PJM FLEET CAPACITY BY PLANT TYPE

Plant Type	Total MW (Summer ICAP)	% of Total PJM Capacity	Recommendation
NGCC	**55,828**	**28%**	**Included**
Coal	**41,554**	**21%**	**Included**
Nuclear	**32,556**	**16%**	**Included**
Simple Cycle CT	**28,496**	**14%**	**Included**
Wind	**9,911**	**5%**	**Included**
ST O&G	**9,240**	**5%**	**Included**
Solar	**7,790**	**4%**	**Included**
Pumped Storage	5,243	3%	Unit-specific review
Hydro	3,319	2%	Unit-specific review
Other	3,427	2%	Unit-specific review
PJM Total Installed Capacity	**197,364**	100%	

Notes and Sources: ABB, Energy Velocity Suite.

The remaining resource types, for which gross costs were not determined, represent a small percentage of PJM's capacity. These resource types either have very few plants in their population and/or highly idiosyncratic costs, making them better candidates for unit-specific reviews rather than a standardized ACR.

III. Gross Costs for Existing Generation

A. Multi-Unit Nuclear Plants

Most nuclear plants in PJM have multiple units installed at the same site. In total, there are currently 14 multi-unit nuclear plants operating in the PJM footprint. The capacity of multi-unit nuclear plants in PJM are mostly in the range of 1,750–2,500 MW, and in most cases these plants are 30–50 years old. There are six states in PJM with nuclear plants, with the most located in Illinois and Pennsylvania.[12] Figure 1 below summarizes the age, size, and locations of these plants.

[12] The Hope Creek plant in New Jersey is classified as a multi-unit plant because it is co-located with the Salem nuclear plant. Figure 1 shows them as if they were a single 3-unit plant.

Based on our experience estimating costs for nuclear plants, the most significant cost drivers for nuclear plants are the plant size and number of units, reactor type such as the boiling water reactor (BWR) versus the pressurized water reactor (PWR), the location (which impacts property taxes and operating costs), the business model (merchant generation vs. regulated cost-of-service generation), and the operator's fleet size.

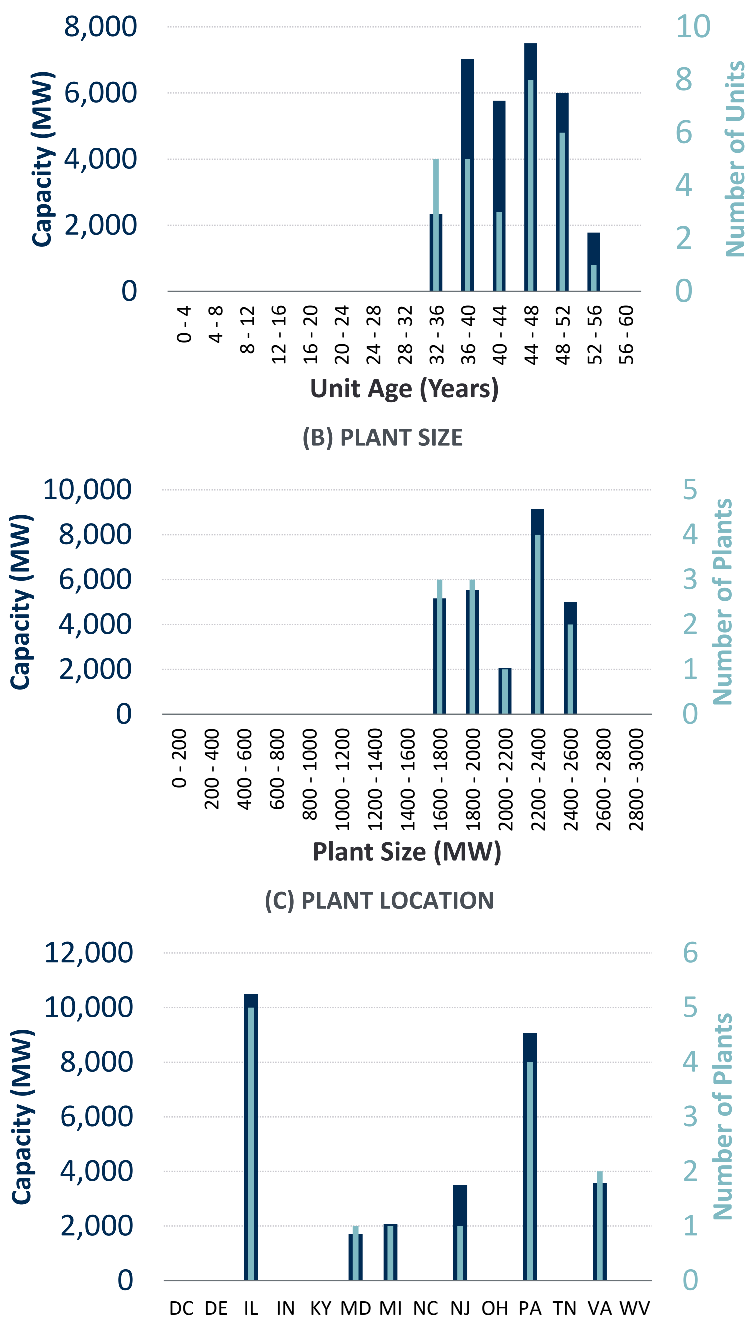
Representative Multi-Unit Nuclear Plant Characteristics

To choose a representative multi-unit nuclear plant we first determined the median plant size of the most frequent size bin of the nuclear fleet, which was between 2,200 MW to 2,400 MW as shown in Figure 1, Panel (B). We then filtered the multi-unit fleet data by this size bin (2,200 MW to 2,400 MW) and compared the median age of the filtered population to the median age of the unfiltered total multi-unit nuclear fleet and found that both were aligned, so we defined the representative age as the median of the fleet (44-years old). We then compared the reactor types, the locations, and the owners' business model and size in this filtered population to the overall fleet. Based on this approach, the representative multi-unit nuclear plant is a 44-year-old 2,400 MW (comprised of two 1,200 MW units) BWR merchant plant in Illinois with an owner that operates multiple plants.

Given the limited number of nuclear plants and limited size variation, we did not alter the plant size for the representative low and high cost plants. For the representative low-cost plant, we chose a pressurized water reactor plant in Virginia, since PWRs have lower operating costs and Virginia has lower labor costs. For the representative high-cost plant, we assumed a plant similar to the representative plant but with the plant owner only operating a single plant, which would have higher costs due to reduced economies of scale.

FIGURE 1: MULTI-UNIT NUCLEAR FLEET CHARACTERIZATION

(A) UNIT AGE



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Multi-Unit Nuclear Plant

Our cost estimates for nuclear plants rely the 2022 NEI "Nuclear Plants in Context" study, with adjustments to best reflect the representative plant and PJM's characterization of "gross" versus variable costs, as described below.[13] Corresponding to the NEI report's , we present nuclear cost components as ongoing capital expenditures and operating costs, then add property taxes, which NEI did not estimate.

Ongoing Capital Expenditures: NEI's capital cost category includes capital spares, regulatory, infrastructure, information technology, enhancements, and sustaining costs (including insurance costs). To estimate the capital cost contribution to gross costs (and variable costs) for PJM multi-unit nuclear plants, we started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of inflation at 7.66%.[14] We then adjusted this value downward by 16.73% to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator.[15] These adjustments yielded a total capital cost of $4.93/MWh in 2022 dollars. From this total, Capital Spares (1.2% of total capital costs) are excluded from the gross costs and counted as variable costs instead, consistent with PJM's tariff. Sustaining costs (37.2% of total capital costs) also are considered variable and excluded from the gross costs, since this category reflects investments in systems directly related to electric production that are necessary to maintain plant performance. In contrast to our prior approach in the 2020 Gross ACR Study, and in response to stakeholder feedback, we included the Enhancements component (36.3% of total capital costs) in the gross costs. These costs are part of continuing the life the plant, and they are incurred fairly consistently by the fleet over time; and they belong in gross costs as opposed to variable costs because they are not directly related to electricity production. The remaining 25.3% of capital costs include upgrades to the plant that are expected to occur on an annual basis and are not directly related to electricity production, so they too are included as a gross case. The resulting contribution of capital costs to multi-unit nuclear plants' gross costs is $3.04/MWh, and $1.89/MWh as part of variable costs (all in 2022 dollars).

13 Nuclear Energy Institute, Nuclear Costs in Context, October 2022 ("NEI Report").

14 U.S. Bureau of Labor Statistics, Consumer Price Index US City Average. Value obtained from 2022 January to October average CPI divided by 2021 average CPI or 291.735/270.970 = 1.0766.

15 NEI tabulated values included sensitivities for these characteristics, each of which were considered as a percentage change from the national average. The averages of these percentages were applied to the national average CapEx to yield the 16.73% net adjustment.

Non-Fuel Operating Costs: NEI's operating cost category includes engineering, loss prevention, materials and services, fuel management, operations, support services, training, and work management. We started with the 2021 average operating costs for all nuclear plants in the U.S. of $18.07/MWh, plus a year of GDP inflation at 7.66%.[16] We then adjusted this value upward by 1.74% to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $19.79/MWh in 2022 dollars. The components of operating costs primarily reflect labor costs that are not directly attributable to the production of electricity and so are included in the gross costs. We interpret the Materials & Services costs (1.5% of total operating costs) to account for consumables required to operate the nuclear plants and thus include those costs as variable operating costs but exclude them from the gross costs. The remaining 98.5% of the total operating costs are included in the gross costs. We applied these percentages to the total operating costs for a multi-unit BWR plant to calculate the variable and fixed operating costs. The resulting contribution of operating costs to multi-unit nuclear plants' gross costs is $19.50/MWh, and $0.30/MWh as part of variable costs (all in 2022 dollars).

Property Taxes: Property tax costs were determined using S&L's project database and expertise. S&L's discussions with operators of nuclear facilities determined broad ranges of taxes are assessed on nuclear facilities depending on the location. We selected a median annual value of $1.01/MWh from this dataset and applied the same value to all nuclear units.

These capital, operating, and property tax cost components are combined to estimate the total gross costs shown in Table 2. The result for the representative multi-unit nuclear plant in PJM is $537/MW-day (in 2022 dollars). The estimated variable costs for the representative multi-unit nuclear plant are $2.19/MWh. For the representative low-cost plant, estimated gross costs are $476/MW-day and variable costs are $2.22/MWh. For the representative high-cost plant, estimated gross costs are $552/MW-day and variable costs are $2.20/MWh.

[16] See footnote 14.

TABLE 2: MULTI-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Multi-Unit Nuclear Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	2,400	2,400	2,400
Gross Costs	*$/MW-day*	$476	**$537**	$552
Capital Costs	*$/MW-day*	$72	**$69**	$69
Fixed Operating Costs	*$/MW-day*	$381	**$445**	$460
Property Taxes	*$/MW-day*	$23	**$23**	$23
Non-Fuel Variable Costs	*$/MWh*	$2.22	$2.19	$2.20
Operating Costs	*$/MWh*	$0.25	$0.30	$0.31
Major Maintenance	*$/MWh*	$1.96	$1.89	$1.90

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[17]

As described in Section I.A above, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder and includes activities such as repair, replacement, and major inspection. If PJM were to determine that major maintenance should instead be considered in gross costs and adapts its tariff accordingly, this would move the major maintenance adder ($1.89/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $43/MW-day, to $580/MW-day. For the representative low-cost plant, this would move $1.96/MWh out of variable costs and increase the gross costs by $45/MW-day to result in $521/MW-day. For the representative high-cost plant, this would move $1.90/MWh out of variable costs and increase the gross costs by $43/MW-day to result in $596/MW-day.

B. Single-Unit Nuclear Plants

There are currently only two single-unit nuclear plants in the PJM market: the 894 MW Davis Besse plant and 1,240 MW Perry plant in Ohio.[18] Due to the small number of plants and the limited variation among them, we specified a single representative plant to be a 38-year-old 1,200 MW Boiling Water Reactor (BWR) unit in Ohio. With such a small population, we did not

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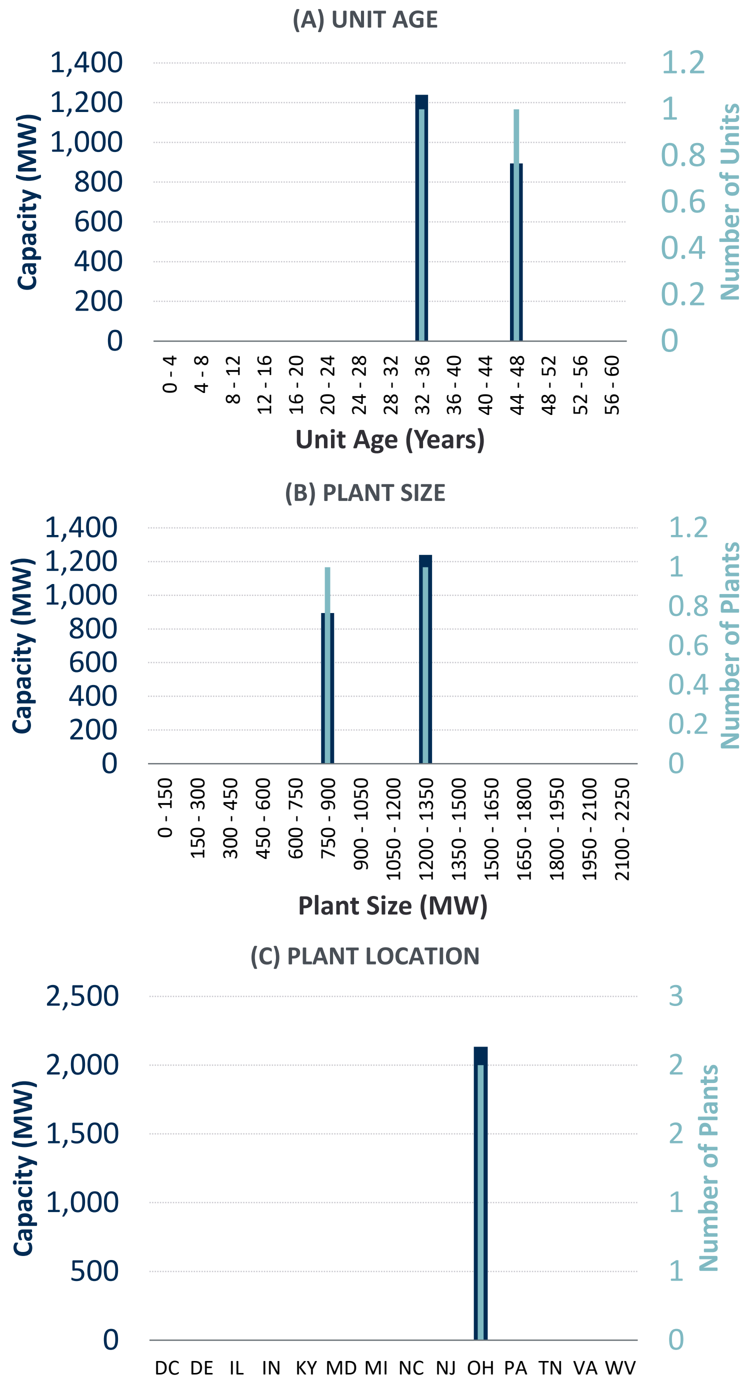
[17] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

[18] See footnote 12, on the treatment of the Hope Creek plant in New Jersey.

designate a representative high or representative low-cost plant. Figure 2 below summarizes the age, size, and locations of these plants.

FIGURE 2: SINGLE-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Single-Unit Nuclear Plant

Costs for the single-unit nuclear plant are estimated from NEI data in the same way as for multi-unit plants. The capital and operating costs are higher per MWh, but the property taxes are assumed to be the same per MWh.

Ongoing Capital Expenditures: following the same approach outlined above for multi-unit nuclear plants, we estimated annual avoidable capital costs of $3.38/MWh as part of gross costs and $2.11/MWh as variable costs based. We started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of GDP inflation at 7.66%.[19] We then adjusted this value downward by 7.27% to account for the representative plant characteristics, including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. As with multi-unit nuclear plants, the gross costs exclude Capital Spares and Sustaining costs but include Enhancements and the remaining capital costs, using the same percentages as for multi-unit nuclear plants.

Non-Fuel Operating Costs: We estimated avoidable fixed operating costs of $21.52/MWh and variable operating costs of $0.33/MWh for a single-unit BWR nuclear plant, just as described above for multi-unit nuclear plants. We started with the 2021 average operating costs for all U.S. nuclear plants of $18.07/MWh, plus a year of GDP inflation at 7.66%.[20] We then adjusted this value upward by 12.32% to account for the representative plant characteristics including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $21.85/MWh in 2022 dollars. As with multi-unit nuclear plants, the gross costs includes 98.5% of that, with only Materials & Services costs attributed to variable costs.

Table 3 below shows the resulting gross costs for a representative single-unit nuclear plant in PJM to be $591/MW-day (in 2022 dollars). The estimated variable costs for a single-unit nuclear plant are $2.44/MWh (in 2022 dollars).

[19] See footnote 14.

[20] See footnote 14.

TABLE 3: SINGLE-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

	Units	Single-Unit Nuclear Plant
Capacity	*Nameplate MW*	1,200
Gross Costs	*$/MW-day*	**$591**
Capital Costs	*$/MW-day*	**$77**
Fixed Operating Costs	*$/MW-day*	**$491**
Property Taxes	*$/MW-day*	**$23**
Non-Fuel Variable Costs	*$/MWh*	$2.44
Operating Costs	*$/MWh*	$0.33
Major Maintenance	*$/MWh*	$2.11

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[21]

Similar to the multi-unit plant, if PJM determines major maintenance should be considered in gross costs instead of variable energy costs and adapts its tariff accordingly, this would move the major maintenance adder ($2.11/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $48/MW-day, to $639/MW-day.

C. Coal Plants

The fleet of existing coal plants in PJM comprises a wide range of sizes, ages, and locations. There are over 120 existing coal units currently in the PJM market at approximately 60 different plant sites. Plant capacities range from less than 100 MW to nearly 3,000 MW with the average plant size of about 700 MW across all plants and 1,100 MW for plants that are at least 100 MW. Over half of the coal capacity is between 35–60 years old, with one plant dating back to 1942, and a few plants having come online in the last 10 years. West Virginia has the most installed capacity, followed by Pennsylvania and Ohio. The majority of coal plants have a dry lime or wet limestone flue-gas desulfurization (FGD) unit installed. Figure 3 below summarizes the age, size, locations, and pollution controls of these plants.

Coal plants of similar age tend to have similar plant size, configuration, and technology. The primary drivers of cost variability among plants are age (which typically dictates the capacity,

[21] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

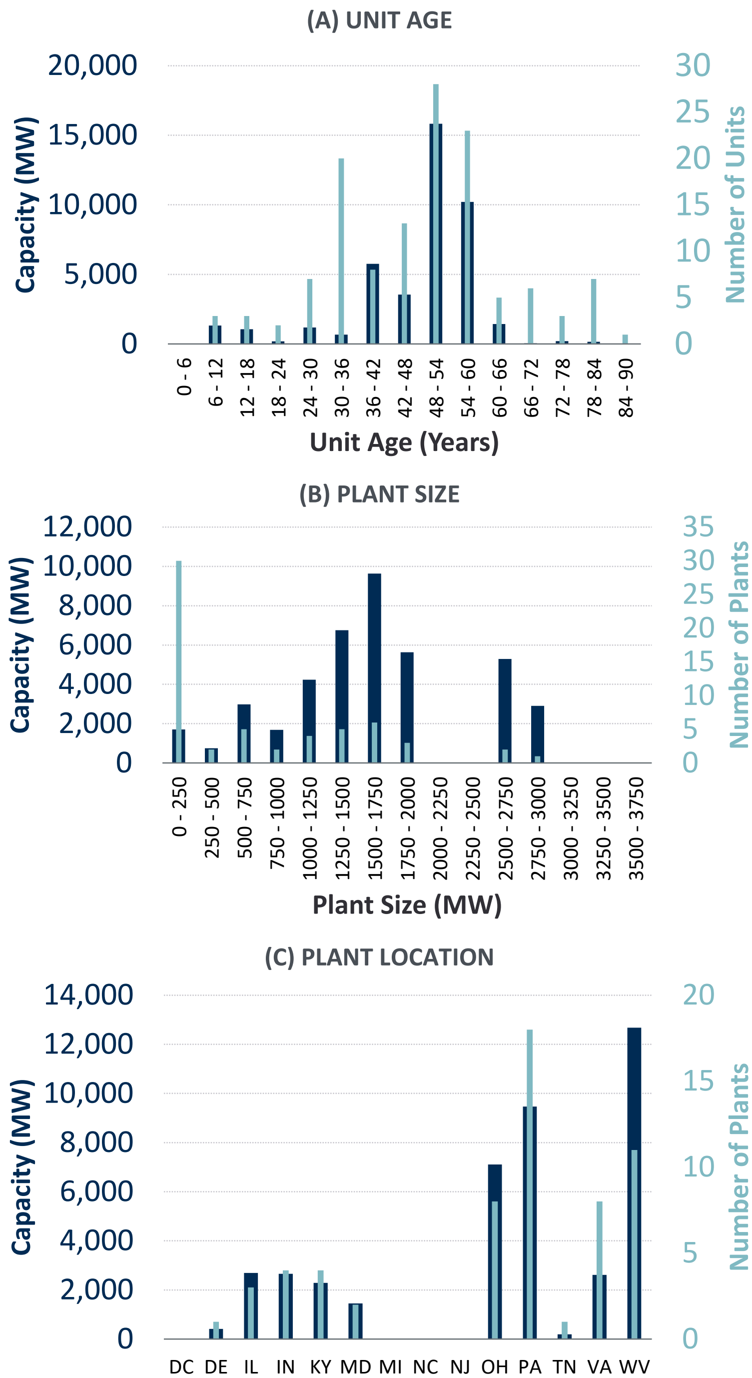
configuration, and technology), followed by the location and the types of post-combustion controls installed at the plant.

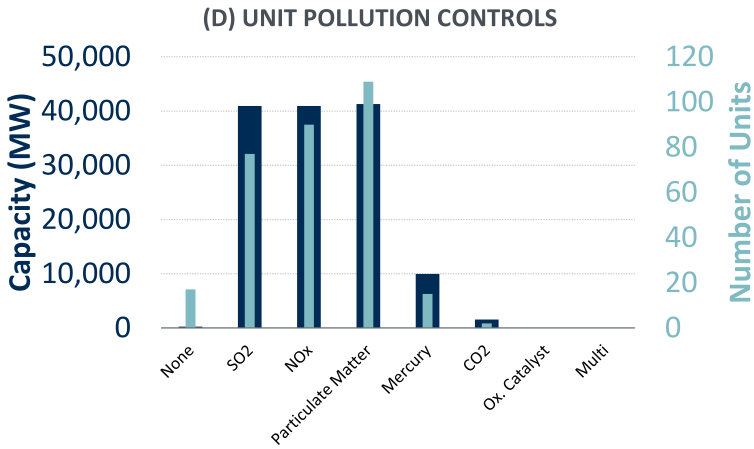
Representative Coal Plant Characteristics

Given that the age of a coal plant influences other cost drivers, we first determined the median plant age within the most frequent age bin of the coal fleet, which was between 48 to 54 years old as shown in Figure 3, Panel (A). We then filtered the coal fleet data by this age bin (48 to 54 years old) and compared the median age of the filtered population to the median age of the unfiltered total fleet. Both measurements were well aligned and were approximately 52 years old. Next, we determined the median capacity of the filtered population and reviewed the plant configurations of the filtered population. Then we reviewed the location of the filtered population and the installed pollution controls these plants had. Based on this approach, the representative coal plant is a 52-year-old 1,500 MW plant (with two 750-MW units) in Pennsylvania that burns Appalachian coal and has a wet limestone FGD unit.

For the representative low-cost plant and representative high-cost plant, we varied the age and capacity of the plant as the main cost differentiators. Because most coal plants in PJM have some type of sulfur dioxide control technology and the majority of them have wet FGD units, we did not change that assumption from the representative plant. To determine the representative high-cost plant, we filtered the fleet data for plants 30-years or younger and determined the median plant size and configuration of this filtered population, which was approximately a 100 MW plant consisting of one unit. We then reviewed the locations of these filtered plants. Based on this approach, the representative high-cost plant is a 30-year old 100-MW plant (one 100-MW unit) with FGD in West Virginia. For the representative low-cost plant, we only varied the capacity of the plant from the representative plant since larger plants would have lower per MW costs, and defined it as a 52-year-old 1,800 MW plant (with two 900-MW units) with FGD in Pennsylvania.

FIGURE 3: COAL FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Coal Plant

We estimated the total annual costs for operating the representative coal plant using data recently released by the EIA and FERC.[22] We reviewed the O&M costs, ongoing capital spending, and cost relationships across a broad range of plant configurations and developed our cost estimates by accounting for differences in unit sizes, number of units at the site, and ages in the reported costs relative to the representative plants. Our adjustments to the reported costs included estimation of staffing requirements, consumption of FGD reagent and other items, and disposal of ash and FGD sludge. The costs of staffing and other fixed expenses account for the economies of scale associated with larger unit sizes and multiple units at a site. We then validated the results against S&L's proprietary data for similar operating coal plants. Finally, where dollar values were referenced from a different year, we escalated the costs to 2022 using annual GDP inflation.[23]

Similar to the nuclear plants, we separated the costs that can be included in the gross costs from those included in the variable cost component of cost-based energy offers. Based on S&L's analysis of FERC Form 1 data and regression model for technically similar plants, a 52-year-old 1,500 MW coal plant would be expected to invest about $36 million in capital expenditures per year into the systems directly attributable to electricity production, which would be accounted

[22] EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018; Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

[23] See footnote 14.

for in the variable cost "maintenance adder" based on PJM's current market rules.[24] Assuming a 50% capacity factor, the maintenance adder contributes about $5.47/MWh to variable costs.[25] Meanwhile, the gross costs estimate includes fixed operating costs that are not directly attributable to electricity production, such as labor, administrative costs, preventative maintenance to auxiliary equipment (buildings, HVAC, water treatment), insurance, and support services.

Property tax rates vary by municipality or even by property where sometimes there are negotiated payment in lieu of taxes (PILOT) agreements, and plant values are not assessed in a uniform manner. To estimate property taxes for the representative coal plant, we surveyed actual property taxes payed by plants that were close to the representative plant size and applied the median value. We also leveraged this analysis to estimate insurance costs. Like property taxes, insurance costs depend on the value of the plant, although the costs are generally not publicly available. S&L has in the past shown that insurance costs tend to be roughly three times as high as property taxes paid by large thermal plants in S&L's project database, and we applied this multiplier. Both turned out to be very small.

Table 4 below shows that the estimated gross costs for the representative coal plant are $94/MW-day (in 2022 dollars), and the variable costs are estimated at $10.92/MWh. For the representative low-cost coal plant, estimated gross costs are $88/MW-day variable costs are $10.47/MWh. For the representative high-cost coal plant, estimated gross costs are $142/MW-day, and variable costs are $9.61/MWh.

24 PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

25 The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

TABLE 4: COAL PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Coal Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	1,800	1,500	100
Gross Costs	*$/MW-day*	$88	**$94**	$142
Labor	*$/MW-day*	$38	**$41**	$60
Fixed Expenses	*$/MW-day*	$48	**$51**	$79
Property Taxes	*$/MW-day*	$0.5	**$0.5**	$0.5
Insurance	*$/MW-day*	$1.5	**$1.5**	$1.5
Non-Fuel Variable Costs	*$/MWh*	$10.47	$10.92	$9.61
Operating Costs	*$/MWh*	$5.00	$5.45	$5.62
Maintenance Adder	*$/MWh*	$5.47	$5.47	$3.99

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and insurance. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 50% capacity factor for the low-cost and median representative plants, and 62% for the high-cost representative plant.[26]

D. Natural Gas-Fired Combined-Cycle Plants

Nearly all natural gas-fired combined-cycle (CC) plants have been built over the past 25 years, with more than 22,000 MW installed in the past 5 years, and most of the rest built in the early 2000s. Plants built in the early 2000s are in the 500 MW to 1,000 MW range while more recent projects typically exceed 1,000 MW. Many of the gas CCs have been built in regions with access to low-cost gas via pipelines or within gas supply basins, predominantly in Pennsylvania, followed by Virginia, Ohio, and New Jersey. Most are equipped with Selective Catalytic Reduction (SCR) to reduce emissions of nitrogen oxides (NO_x). Figure 4 below summarizes the age, size, locations, and pollution controls of these plants.

The main drivers of cost variability among CCs are the capacity, age, turbine type, plant configuration, and whether or not a plant has firm gas transportation service. Location is a secondary driver, through its effects on the costs of labor, property taxes, and firm fuel.

[26] The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

Determination of Representative Natural Gas-Fired Combined-Cycle Plant Characteristics

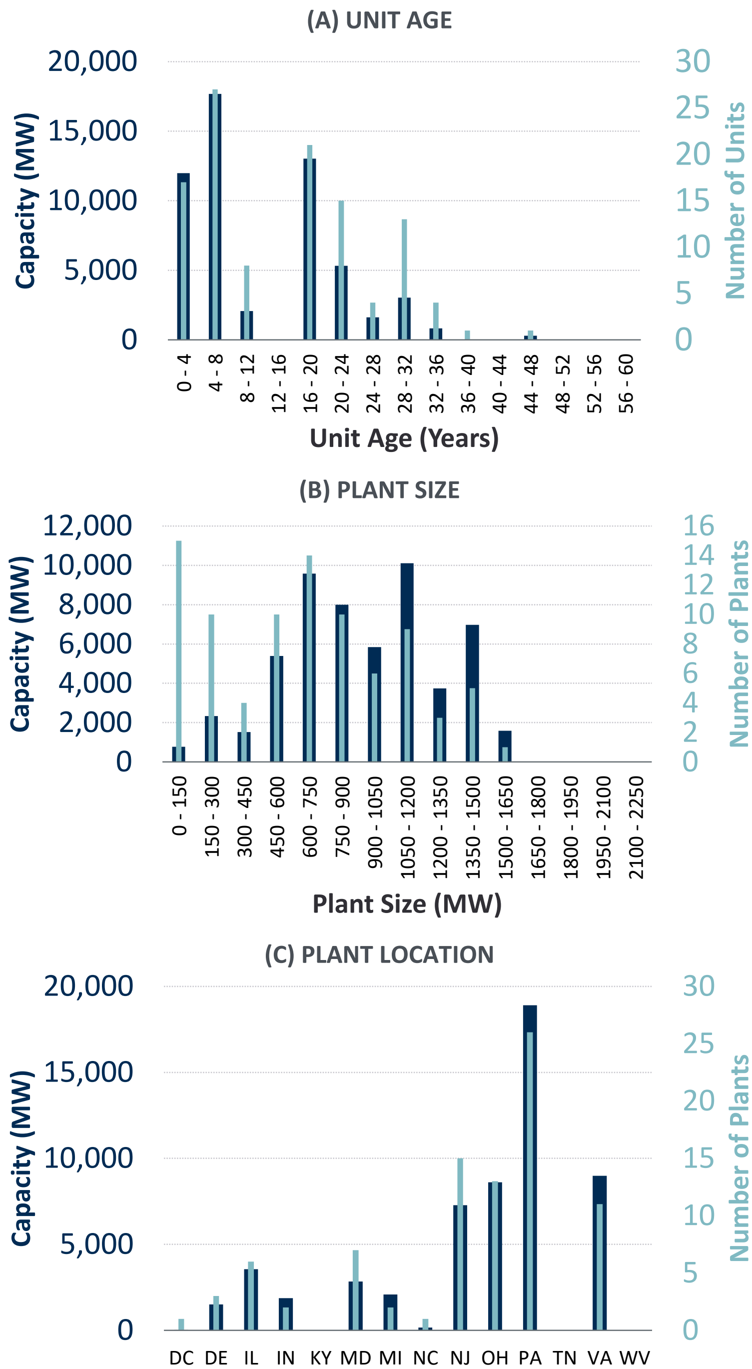
We relied on input from PJM indicating that the majority of existing CC plants have firm gas transportation contracts up to their economic maximum (EcoMax), and therefore the representative plant would be subject to this cost. Then we determined the median plant size of the CC fleet, which was 669 MW in the 600 MW to 750 MW bin as shown in Figure 4, Panel (B). We then filtered the CC fleet data for plants between 600 MW to 750 MW and compared the median age of the filtered population to the median age of the unfiltered total CC fleet and found that both were aligned, so we defined the representative age as the median of the fleet (11-years old). We then compared the plant configuration, location and the installed pollution controls in this filtered population to determine that most plants are in a 2×1 configuration, nearly all plants have SCR installed, and most are located in Pennsylvania. 11 years ago, F-class turbines were the predominant turbine technology, which had standardized sizes when employed in a 2×1 configuration. We adjusted the reference size to 750 MW to account for this standardization. Based on this approach, the representative gas CC plant is an 11-year-old 750 MW plant with two F-class gas turbines and one steam turbine (2×1) configuration in Pennsylvania that has SCR technology installed and has firm gas transportation service.

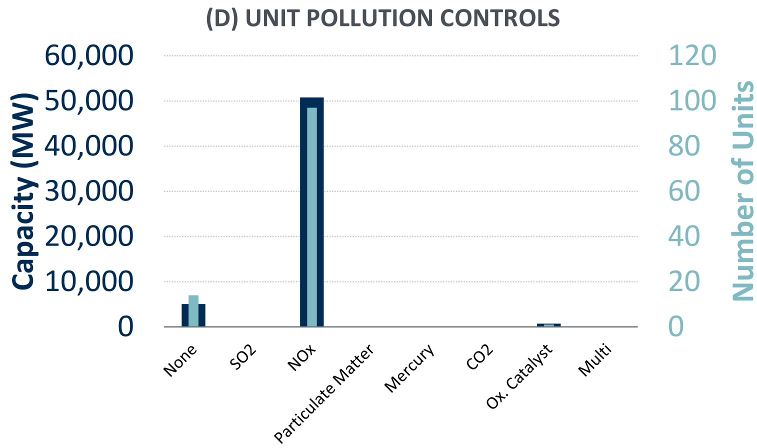
The representative high-cost and low-cost plants reflect the two modes of the bi-modal distribution of ages of CC plants in PJM. The older plants are smaller and have higher costs per MW-day, where newer plants are larger and have lower costs per MW-day with their economies of scale. Since nearly all CC plants in PJM have SCR installed for NO_x pollution control, we did not vary this assumption for the representative high or low-cost plants. Because the majority of the CC feet has firm gas up to EcoMax we also assume that the representative low-cost and representative high-cost plants have firm gas transport service as well.

For the representative high-cost plant, we first identified a plant size that was representative of the smaller plants in the fleet. We split the CC fleet into plants smaller than 750 MW and found the median of this sub-population, which were plants between 300 MW to 450 MW. We then filtered the CC sub-population for plants between 300 MW to 450 MW and chose a 400 MW median to represent the smaller/older CCs. New Jersey has the second most CCs in PJM so we chose this location for the representative older/smaller plant. The median CC plant age in New Jersey is approximately 30-years old. We assessed the plant configuration and turbine type of plants in this size range to be an F-class single unit. Based on this approach, the representative high-cost CC plant is a 30-year-old, 400 MW plant, with one F-class turbine in a 1×1 configuration in New Jersey.

For the representative low-cost plant, we identified plants in the 1,050–1,200 MW range, which represents a large proportion of the capacity and a high number of plants as shown in Figure 4, Panel (B). We filtered the CC fleet data by this size bin to obtain the representative low-cost age at a median of 5 years old. We used the CC fleet data filtered by this size to determine the plant configuration, turbine type, and location of the remaining plants. CC plants around this size and age tended to be larger with H-class turbines in a 2×1 configuration. Based on this approach, the representative low-cost CC plant is a 5-year-old 1,100 MW plant with two 550 MW H-class turbines in a 2×1 configuration in Pennsylvania.

FIGURE 4: NATURAL GAS-FIRED COMBINED CYCLE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Natural Gas-Fired Combined-Cycle Plants

To estimate the costs of the representative plants, we relied on the same methodology used to develop cost estimates for gas CCs in the PJM 2022 CONE Study.[27] Similar to how costs are specified in the 2022 CONE Study, we included the hours-based major maintenance costs specified in Long-Term Service Agreements (LTSAs) under variable O&M costs alongside operating costs associated with chemicals and consumables.

We used the cost information from the 2022 CONE Study to estimate components of the fixed O&M, variable O&M, and major maintenance for the representative low-cost plant (H-class 2×1). Other public sources and S&L's project database containing a broad range of CC configurations were used for estimating the cost components for the 750 MW and 400 MW F-class representative plants.

We adjusted the cost data from public sources to account for differences in turbine sizes, configurations, locations, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.[28] These adjustments accounted for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. The costs of major maintenance and consumables were derived using a 62% capacity factor, representative of CCs in PJM. Property taxes and insurance were estimated using the values

27 Newell, et al., PJM CONE 2026/2027 Report, April 21, 2022 ("2022 CONE Study").

28 Adjustments come from S&L project database and public sources including FERC Form 1 and EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

from the 2022 CONE study[29] with downward adjustments made for the older, less valuable plant.

Firm gas transportation costs were estimated at updated average tariff rate of $8.06/Dth per month incorporating reservation and usage charges for major pipelines servicing Pennsylvania under the FT-1 rate schedules.[30] We calculated the average heat rate for all natural gas-fired combined-cycle plants in the PJM fleet to be 7,212 Btu/kWh.[31] We then multiplied the nameplate plant capacity for the representative plants with the heat rate to estimate the average annual gas requirement. We then calculated the annual firm gas cost of $46/MW-day using the average tariff rate of $8.06/Dth per month applied to the annual gas requirement.

Table 5 below shows that the estimated gross costs for the representative plant are $113/MW-day and variable costs are $2.71/MWh (in 2022 dollars). The estimated gross costs for the representative low-cost plant are $94/MW-day and variable costs are $2.36/MWh. Estimated gross costs are higher for the smaller 400 MW representative high-cost plant at $160/MW-day due to the reduced economies of scale. The variable costs for the representative high-cost plant are $2.60/MWh.

Note that the $113/MW-Day gross costs of the representative existing CC plant are similar to the Fixed O&M costs for new CCs from the 2022 CONE Study as part of the Quadrennial Review.[32] Accounting for updates incorporated into the final submitted CONE values[33] and deflating those estimates to 2022 dollars, the Fixed Operation & Maintenance cost for the new CCs in the WMACC CONE Areas (most closely corresponding to the "PA" location of the representative existing CC) plant is $83/MW-day. This is $11/MW-day less than the $94/MW-day we are estimating for the gross costs of the comparably sized "Low-Cost" existing plant. The difference is primarily attributable to updated tariffed rates used to estimate the costs of firm fuel, partially offset by lower property taxes and insurance, and other adjustments.

29 2022 CONE Study.

30 The tariff rate used in calculation of firm gas costs was the average of TETCO M3 rate and Transco Zone 6 rate. See Texas Eastern Transmission FERC Gas Tariff, M3-M3 effective August 1, 2022, and Transcontinential Gas Pipeline Company FERC Gas Tariff, Delivery Zone 6 and Receipt Zone 6 effective November 1, 2022.

31 Based on average full load heat rates with data from ABB, Energy Velocity Suite. Many combined-cycle plants employ duct firing to produce higher-pressure steam to increase plant capacity when operating in high ambient temperatures. However, the use of duct firing in CCs causes the efficiency to drop significantly and plants are not designed to be operated constantly with duct firing throughout a year; therefore, we calculate the annual gas requirement using the average full load heat rate without duct-firing.

32 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

33 *Ibid*, Attachment D.

TABLE 5: COMBINED-CYCLE PLANTS' GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Natural Gas Combined Cycle Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	1,100	750	400
Gross Costs	*$/MW-day*	$94	**$113**	$160
Labor	*$/MW-day*	$17	**$21**	$32
Fixed Expenses	*$/MW-day*	$52	**$72**	$120
Property Taxes	*$/MW-day*	$6	**$5**	$2
Insurance	*$/MW-day*	$19	**$15**	$6
Non-Fuel Variable Costs	*$/MWh*	$2.36	$2.71	$2.60
Operating Costs	*$/MWh*	$0.75	$0.52	$0.94
Maintenance Adder	*$/MWh*	$1.61	$2.19	$1.66

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and firm gas transportation service. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 62% capacity factor.

E. Simple-Cycle Combustion Turbines

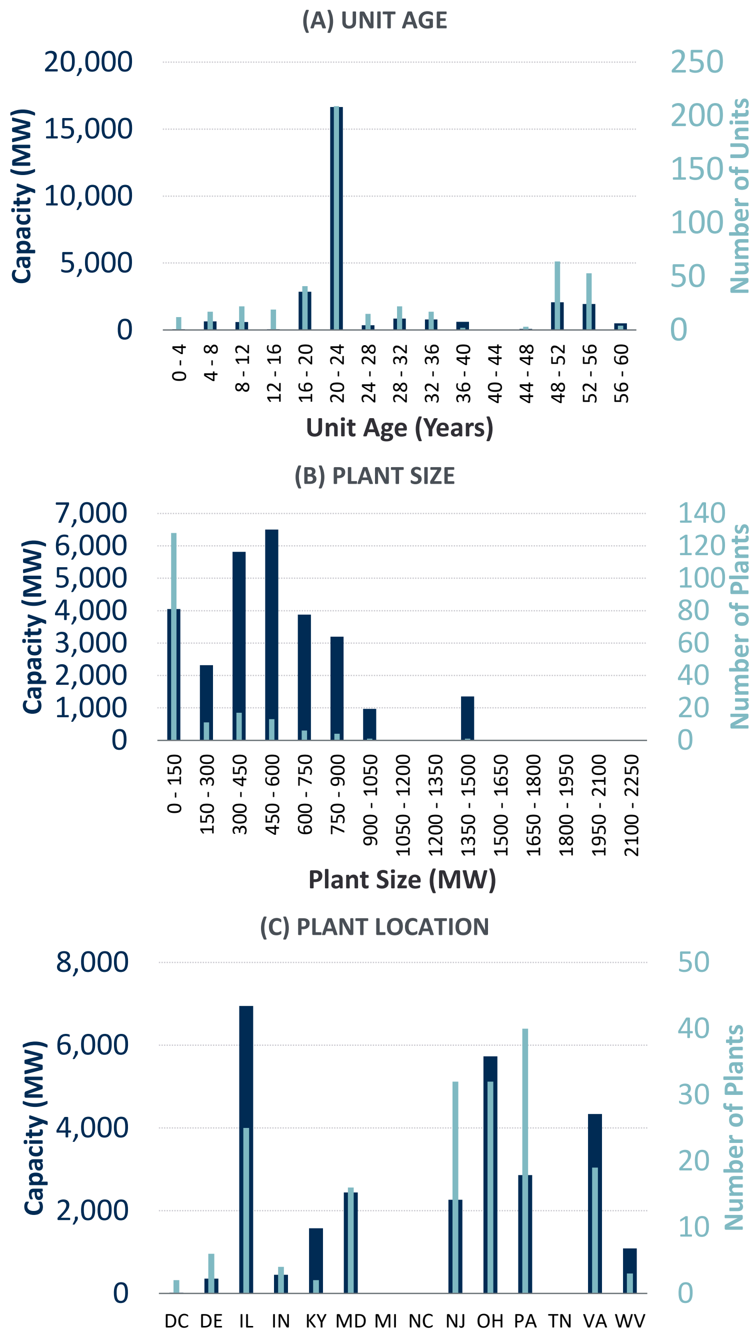
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. There are many CT plants in the PJM fleet under 150 MW, but these plants cumulatively do not constitute a large amount of capacity compared to the larger plants in the 300–600 MW range. Most were built 20–24 years ago and the states with the most CTs include Ohio, Illinois, Pennsylvania, New Jersey, and Virginia. Unlike CCs, most CTs are not built with an SCR unit. Figure 5 below summarizes the age, size, locations, and pollution controls of these plants. The primary cost drivers for CTs are capacity, age, turbine type and configuration, and location.

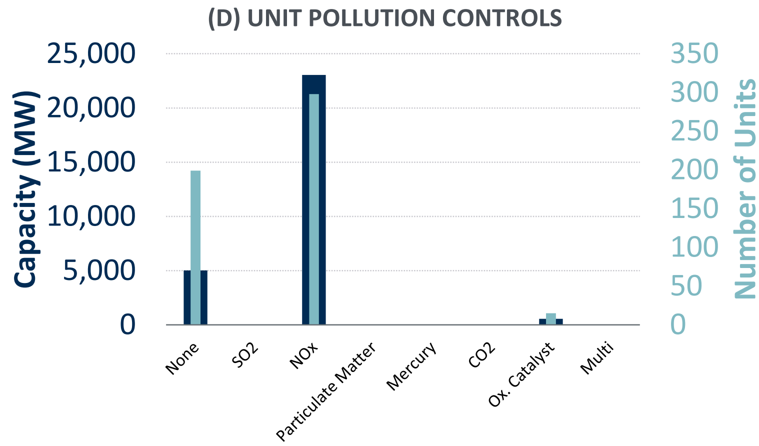
Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics

The median size of the fleet was 320 MW between the 300 MW to 450 MW size bin, as shown in Figure 5, Panel (B). We compared the median age of the CT fleet to the median age of the filtered population and found that both were approximately 20 years old. 20 years ago, F-class turbines were the predominant turbine technology. We then reviewed the location and configuration of the filtered population. Based on this approach, the representative CT plant is a 20-year-old 320 MW plant with two F-class turbines (2×160 MW) located in Illinois. Unlike CC plants, the majority of existing CT plants do not have firm gas transportation contracts up to EcoMax, according to PJM, so transportation costs were not included.

Because nearly all CT plants were built around the same time, we did not vary the age for the representative low-cost and representative high-cost plants and instead chose the low and high cost representative plant based on other factors. As shown in Figure 5 Panel (B), there are many plants that are less than 150 MW. To determine the representative low-cost plant, we filtered the 20-year-old CT fleet for plants smaller than 150 MW and determined the median capacity of this filtered population, which was 100 MW. Plants of this size were most frequently in Pennsylvania and typically use two LM600 aeroderivative turbines. Based on this approach, the representative high-cost CT is a 100 MW plant with two LM6000 aeroderivative turbines (2×50 MW) in Pennsylvania. To determine the representative low-cost plant, we filtered 20-year-old plants for sizes above 450 MW and found the median size of this filtered population, which was approximately 640 MW. These plants were most frequently in Illinois. Many plants of this size use several E-class turbines. Therefore, the representative low-cost CT is a 640 MW plant with eight E-class turbines (8×80 MW) in Illinois.

FIGURE 5: SIMPLE CYCLE COMBUSTION TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Simple-Cycle Combustion Turbine Plants

To estimate costs, we reviewed cost estimates reported by the 2022 CONE Study, cost estimates from the EIA, and S&L's project database.[34] We then developed the cost estimates for existing CTs similar to the representative plants by adjusting the publicly reported costs for differences in turbine sizes, configurations, locations, and ages. We validated the results of our cost estimates against proprietary data in S&L's project database for similar plants in operation. The adjustments account for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site.

The CT technologies included in the ACR study are significantly different from the selected single GE model 7HA.02 reference technology from the 2022 PJM CONE study, thus estimation of their property taxes and insurance was performed using the most representative references available in S&L's project database. Both property taxes and insurance were estimated based on a regression analysis of similar technologies with adjustments made for the size, type, and age of the CTs in this study. The high-cost plant is an aeroderivative, which is a fundamentally different technology, so costs were estimated from a different data set of similar plants.

The E-class and F-class turbines that operate as peaking units would be expected to trigger major maintenance events based on the number of starts. For this reason, we estimated the variable cost maintenance adder assuming a 10% capacity factor and 12 hours of operation per start. The LM6000 turbines however, would likely trigger major maintenance based on hours of operation therefore their maintenance adder is independent of the number of starts per year.

[34] 2022 CONE Study; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

Table 6 below shows the resulting gross and variable costs for the simple cycle CT plants. The estimated gross costs of the representative CT are $52/MW-day and the variable costs are $4.29/MWh (in 2022 dollars). For the representative low-cost plant, the estimated gross costs are $43/MW-day and variable costs are $4.29/MWh. For the representative high-cost plant, estimated gross costs are $69/MW-day and variable costs are $5.39/MWh.

We also validated these costs against the Fixed O&M costs accepted in PJM's tariff as part of the 2022 CONE Study.[35] Accounting for subsequent updates in later affidavits, and deflating those estimates to 2022 dollars, the published Fixed Operation & Maintenance cost for the same area as the representative plant is $93/MW-day. This value included the cost of firm gas contracts, which amounted to approximately $49/MW-day in 2022 dollars. Excluding the firm gas cost, the 2022 CONE study Fixed Operation & Maintenance cost for new CTs becomes $44/MW-day, which is close to our representative plant gross costs of $52/MW-day. This difference is primarily attributable to the staffing assumptions made for the representative 2×160 MW existing plant compared to the 1×353 MW new plant in the CONE study.

TABLE 6: SIMPLE-CYCLE COMBUSTION TURBINE PLANTS GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Simple Cycle Combustion Turbine Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	640	320	100
Gross Costs	*$/MW-day*	$43	**$52**	$69
Labor	*$/MW-day*	$6	**$10**	$23
Fixed Expenses	*$/MW-day*	$8	**$12**	$28
Property Taxes	*$/MW-day*	$16	**$16**	$3
Insurance	*$/MW-day*	$13	**$13**	$16
Non-Fuel Variable Costs	*$/MWh*	$4.29	$4.29	$5.39
Operating Costs	*$/MWh*	$0.42	$0.42	$0.97
Maintenance Adder	*$/MWh*	$3.88	$3.88	$4.43

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses in the gross costs includes preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. The maintenance adder assumes a 10% capacity factor with 12 hours per start. Actual major maintenance costs will vary with the number of starts, not strictly with MWh as expressed in this table, and will depend on actual duty cycles and maintenance agreement terms.

35 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

F. Oil- and Gas-Fired Steam Turbines

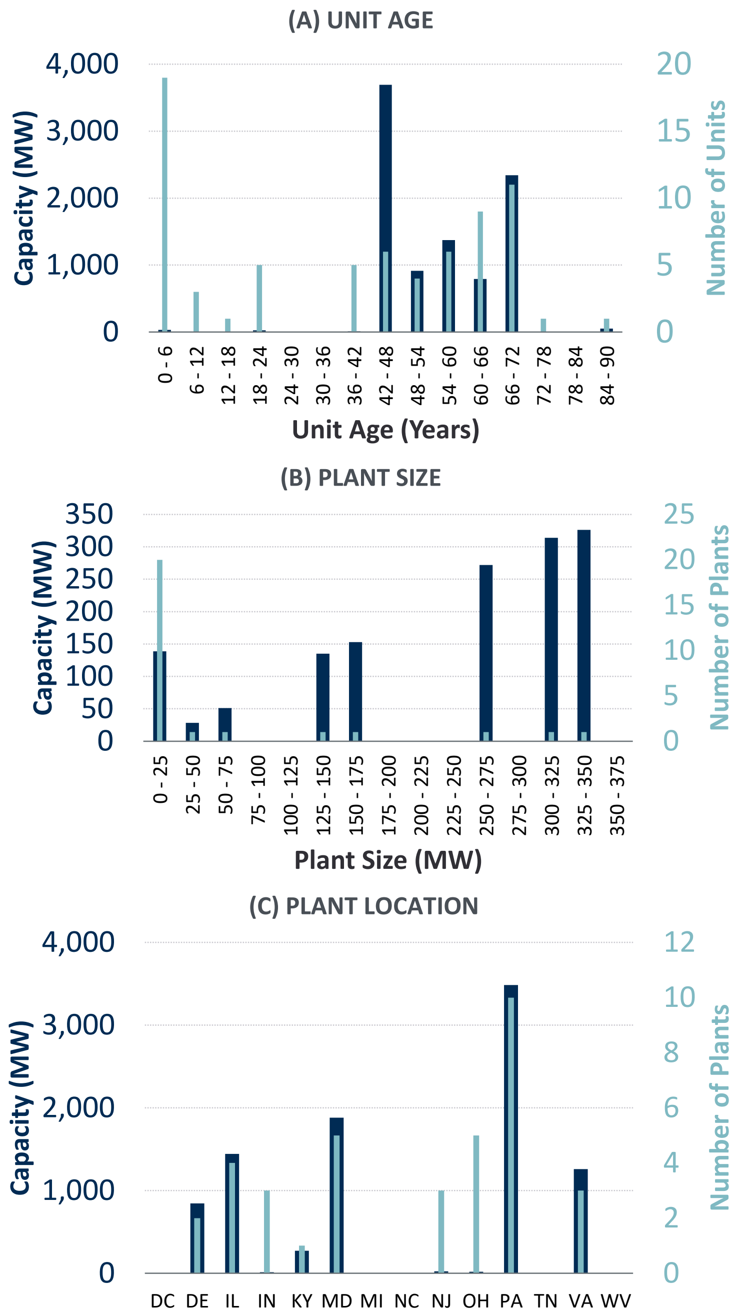
Steam turbine plants fueled by oil and gas (ST O&G) have a wide range of sizes. The majority of ST O&G plants are less than 25 MW but collectively do not contribute much capacity to the fleet. The average size is about 250 MW, which is skewed by a few very large plants on the order of 700 to 1,700 MW. Most of the larger plants and thus most of the capacity is located in Pennsylvania. Smaller plants are in Ohio, Maryland, and New Jersey. Ages of ST O&G plants range from 2–85 years old, with most capacity being 40–50 years old. Figure 6 below summarizes the age, size, locations, and pollution controls of these plants. The primary drivers of cost for ST O&G plants are age, capacity, location, and plant configuration.

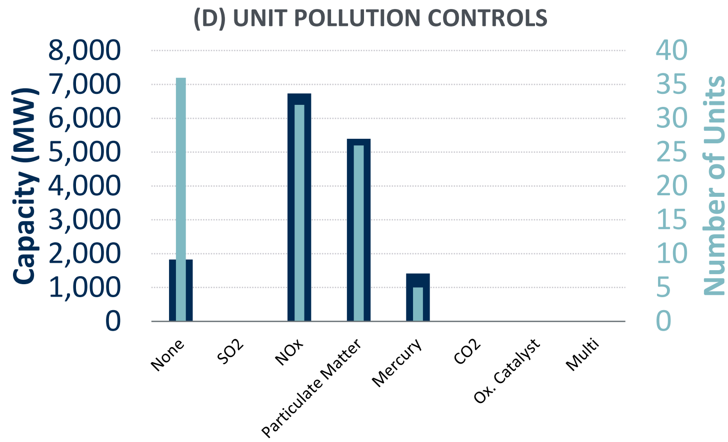
Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics

The median MW in PJM's ST O&G fleet is in a 900 MW plant. We filtered the ST O&G fleet by this approximate size and compared the age of the filtered fleet with the age of the whole fleet. The age bucket contributing the most capacity to the ST O&G fleet are plants aged 42–48 years old, shown in Figure 6, Panel (A). We defined the representative age to be in this bucket (47-years old), which aligned with the ages of the filtered fleet. After further filtering for age, we ensured that the location of our representative plant reflected the location distribution of the whole fleet. The majority of existing ST O&G plants do not have firm gas transportation contracts up to EcoMax, according to PJM. Based on this approach, the representative ST O&G plant is a 47-year-old, 900 MW plant in Pennsylvania, without firm gas.

Since the majority of both ST O&G plants and capacity are in Pennsylvania, we did not vary the location for the representative low- and high-cost plants. To reflect the many small plants in the fleet, we filtered for plants under 900 MW. For plants in Pennsylvania under this size, we chose an approximate median of 350 MW to be the representative high-cost plant size. We then filtered the fleet for plants of approximately 350 MW and found that the median age of these smaller plants was 65 years old. Based on this approach, the representative high-cost ST O&G plant is a 65-year-old, 350 MW plant in Pennsylvania. To identify a representative low-cost plant, we began by selecting a larger plant to reflect economies of scale and filtered for plants above 900 MW. We determined a representative high-cost plant size of 1,300 MW. These larger plants have a median age of 47-years old. Based on this approach, the representative low-cost ST O&G plant is a 47-year old, 1,300 MW plant in Pennsylvania.

FIGURE 6: OIL AND GAS-FIRED STEAM TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite. In Panel (B), the distribution is truncated at 375 MW to maintain legibility, but ST O&G plants range up to 1,700 MW with nine plants above 375 MW.

Cost Estimates for Representative Oil and Gas-Fired Steam Turbine Plant

To estimate the costs of the representative plants, we relied primarily on public cost information from the FERC Form 1, and S&L's project database.[36] We then developed the cost estimates for the representative plants accounting for differences in plant sizes, plant location, and ages based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation. For property taxes and insurance, we used the same survey approach as for coal described in Section III.C above, but in this case based on actual ST O&G plants in PJM. We again estimated insurance costs at three times as high as property taxes. Both turned out to be very small.

Table 7 below shows that the estimated total gross costs for the representative plant are $64/MW-day (in 2022 dollars) and variable costs are $5.81/MWh. For the representative low-cost ST O&G plant, estimated gross costs are $53/MW-day and variable costs are $5.51/MWh. For the smaller 350 MW representative high-cost plant, gross costs are significantly higher, at $102/MW-day, due to the reduced economies of scale; variable costs are $16.26/MWh.

[36] Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

TABLE 7: STEAM OIL & GAS PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Oil and Gas-Fired Steam Turbine Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	1,300	900	350
Gross Costs	*$/MW-day*	$53	**$64**	$102
Labor	*$/MW-day*	$21	**$26**	$43
Fixed Expenses	*$/MW-day*	$26	**$32**	$53
Property Taxes	*$/MW-day*	$1.6	**$1.6**	$1.6
Insurance	*$/MW-day*	$4.8	**$4.8**	$4.8
Non-Fuel Variable Costs	*$/MWh*	$5.51	$5.81	$16.26
Operating Costs	*$/MWh*	$1.19	$1.19	$1.19
Maintenance Adder	*$/MWh*	$4.32	$4.62	$15.07

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general expenses. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders for the low-cost and representative plant assume a 20% capacity factor and the maintenance adder for the high-cost plant assumes a 10% capacity factor.

G. Onshore Wind Plants

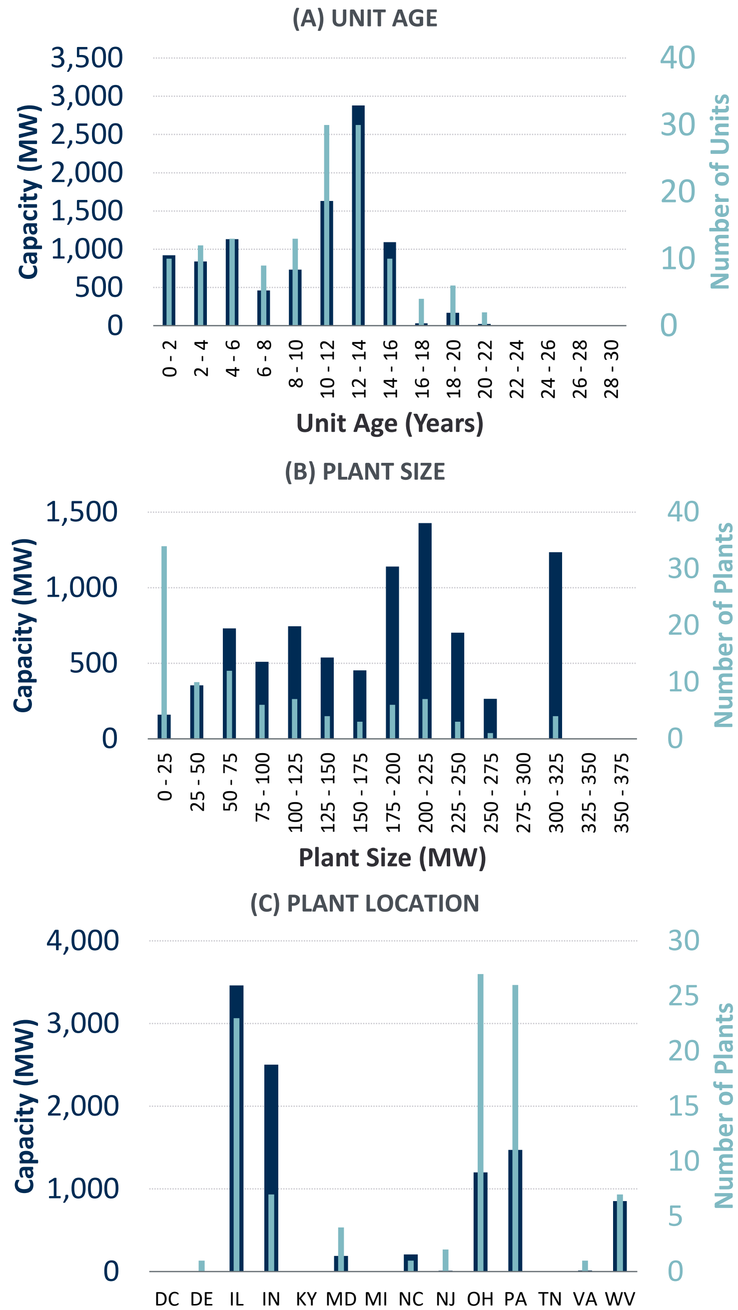
Over the past 15 years, nearly 10,000 MW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by the numerous small plants (less than 25 MW); however, 17 are at least 200 MW as shown in Figure 7 Panel (B) below. Plants larger than 100 MW make up of over 80% of the total capacity in PJM, and most are located in Illinois and Indiana, while smaller plants are located in Pennsylvania and Ohio. Ages of wind plants range from less than a year old to 20 years old. Figure 7 below summarizes the age, size, and locations of these plants. The primary cost drivers for wind plants tend to be the size and location, then the age and density of individual wind turbines at a plant site.

Determination of Representative Onshore Wind Plant Characteristics

To determine the representative onshore wind plant, we filtered the wind fleet for plants greater than 100 MW (since these plants contribute to more than 80% of the total capacity) and determined the median plant size of this filtered population, which was approximately 200 MW. We then found the median age of this filtered fleet, which was approximately 12 years old and reviewed the most frequent location, which was Illinois. Based on this approach, the representative onshore wind plant is a 12-year-old, 200 MW plant in Illinois.

To account for the size and age variation of the fleet, we varied these characteristics when determining the representative low-cost and representative high-cost plant. We filtered the wind fleet for plants less than 100 MW and determined a median size of 30 MW for the representative high-cost plant. We then found the median age of this filtered fleet, which was similar to the age for representative plants, so we maintained a 12-year-old plant. The most frequent location of these smaller plants was Pennsylvania. Based on this approach, the representative high-cost plant is a 12-year-old 30 MW plant in Pennsylvania. We increased the capacity for the representative low-cost plant to be a 300 MW plant, the median size for plants above 200 MW. By filtering for larger plants, we determined that the median age was slightly younger than the representative high-cost plant (10 years old) and the most frequent location was in Illinois. Based on this approach, the representative low-cost plant is a 10-year-old 300 MW plant in Illinois.

FIGURE 7: ONSHORE WIND PLANTS FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 375 MW to maintain legibility, but wind plants range up to about 900 MW with two plants larger than 375 MW.

Cost Estimates for Representative Onshore Wind Plants

We estimated fixed and variable O&M and capital costs for the representative wind plants by first reviewing recent public sources and S&L's project database.[37] We then developed the cost estimates for the representative plants accounting for differences in MW capacity, plant location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative wind plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the total fixed operating expenses based on S&L's project database for similar sized wind plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 8 below shows resulting gross costs for the representative plant of $147/MW-day (in 2022 dollars). We assumed that all of the costs necessary to operate a wind plant (and a solar PV plant) are fixed and belong in the gross costs, with no variable costs. The representative low-cost plant's estimated gross costs are $140/MW-day, and the representative high-cost plant's gross costs are $204/MW-day.

[37] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 8: ONSHORE WIND PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Onshore Wind Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	300	200	30
Gross Costs	*$/MW-day*	$140	**$147**	$204
Labor	*$/MW-day*	$26	**$27**	$50
Fixed Expenses	*$/MW-day*	$95	**$99**	$126
Property Taxes	*$/MW-day*	$12	**$13**	$17
Insurance	*$/MW-day*	$8	**$8**	$11
Non-Fuel Variable Costs	*$/MWh*	$0.00	$0.00	$0.00
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled wind turbine and balance-of-plant maintenance, parts and consumables, operations monitoring, land lease, general and administrative costs.

H. Large Scale Solar Photovoltaic Plants

Large-scale solar photovoltaic (PV) plants tend to be fairly small in PJM, with most plants under 10 MW and a few in the 50–100 MW range. All of the solar PV plants have been built in the past 15 years, with the most capacity added in Virginia, New Jersey, and North Carolina. Figure 8 below summarizes the age, size, and locations of these plants.

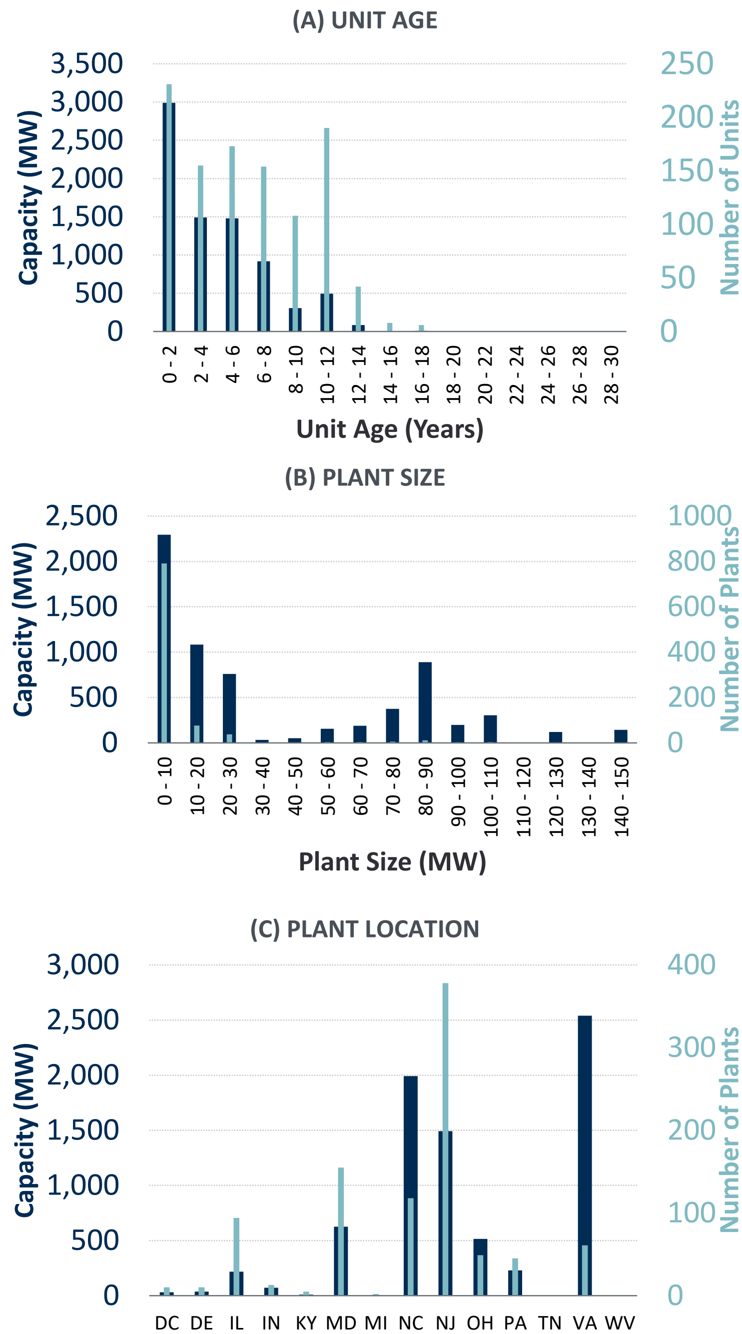
The age of a solar plant influences the plant capacity since more recent plants have tended to be built larger than in the past. Location also impacts the costs of solar PV plants due to differences in labor costs and property taxes.

Determination of Representative Large Scale Solar Photovoltaic Plant Characteristics

Because the age of a solar plant influences the plant size, to choose a representative solar plant we first determined the median age of the fleet, which was 5 years old. We filtered the solar fleet data by this age and compared the median plant size of this population to the median plant size of the fleet, which was approximately 10 MW. Then we reviewed the location of the fleet and the population with age and size filters. Based on this approach, the representative plant is a 10 MW single-axis tracking solar PV plant in New Jersey built 5 years ago.

For the representative high and low-cost plants, we varied size and age as the cost differentiators. The solar fleet is largely small plants 10 MW and under. For higher-cost plants under 10 MW, the median capacity is 2 MW. We filtered the solar fleet for plants of this size and determined these plants were slightly older than our representative plant (7 years old). We then analyzed the location of these smaller plants and found that they aligned with the most common location of the overall fleet, so we maintained the location as New Jersey. The representative low-cost plant would be much larger, but we avoided plants less than 5 years old because of the maintenance warranties that apply to younger plants and are not representative of the entire fleet. We filtered the entire fleet data by plants between 80–90 MW. The larger plants were most frequently located in North Carolina. Based on this approach, the representative low-cost plant is an 80 MW 5-year-old plant in North Carolina.

FIGURE 8: LARGE SCALE SOLAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 150 MW to maintain legibility, but Solar PV plants range up to 500 MW with five plants larger than 150 MW.

Cost Estimates for Representative Large Scale Solar Photovoltaic Plants

We estimated fixed and variable O&M and capital costs for the representative solar PV plants by reviewing recent public sources and S&L's project database.[38] We then developed the cost estimates for the representative solar PV plants accounting for differences in the solar panel type, tracking type, plant size, location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative solar plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the overnight capital cost of the installation based on S&L's project database for similar sized solar plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks such as potential for damage from hail, or other natural disasters. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 9 below shows that we estimated gross costs for the representative solar PV plant to be $70/MW-day (in 2022 dollars). Similar to onshore wind plants, we assumed that all of the costs necessary to operate a solar PV plant are fixed costs that are not directly attributable to the production of electricity, and thus did not include any variable costs for the solar PV plants. We estimated the representative low-cost gross costs to be $65/MW-day and the representative high-cost plant to be $74/MW-day.

[38] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 9: SOLAR PV PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Large Scale Solar Photovoltaic Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	80	10	2
Gross Costs	*$/MW-day*	$65	**$70**	$74
Labor	*$/MW-day*	$20	**$22**	$25
Fixed Expenses	*$/MW-day*	$30	**$33**	$36
Property Taxes	*$/MW-day*	$5	**$4**	$4
Insurance	*$/MW-day*	$10	**$10**	$10
Non-Fuel Variable Costs	*$/MWh*	$0.00	$0.00	$0.00
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled PV and BOP equipment maintenance, vegetation management, module cleaning, major maintenance reserve funds, land lease, general and administrative costs.

PJM CONE 2026/2027 Report

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NOTICE

TABLE OF CONTENTS

Executive Summary

PJM Interconnection, L.L.C (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff. This report presents our estimates of the Cost of New Entry (CONE) for the 2026/2027 commitment period, recommendations regarding the methodology for calculating the net energy and ancillary service revenue offset (E&AS Offset), and our recommendation for the selection of the reference resource. A separate, concurrently-released report presents our review of the VRR curve shape.

Background

The Variable Resource Requirement (VRR) curves set the price at the target reserve margin at approximately Net Cost of New Entry (Net CONE), such that the resource adequacy requirement will be achieved if suppliers enter the market when prices are at least Net CONE. In a downward-sloping curve, slightly lower reliability will be tolerated only when prices exceed Net CONE and some incremental capacity will be procured when the incremental cost is relatively low.

Net CONE is estimated by selecting an appropriate reference resource that economically enters the PJM market, determining its characteristics and its capital costs and ongoing operating and maintenance costs; then estimating a first-year capacity payment needed for entry, given likely trajectories of future total revenues and E&AS offsets.

A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support. Another common misconception is that the Net CONE parameter sets capacity prices. In fact, capacity prices are determined by the intersection of the VRR curves and the supply curves. Long-run market clearing prices depend on the actual prices at which new competitive supply is willing to enter rather than the administrative Net CONE estimates, while the VRR curve determines only the quantity of capacity procured (short-term price impacts of changes in administrative Net CONE may be larger, depending on the elasticity of supply).

Reference Resource

The reference resource should be feasible to build within the three-year period between the Base Residual Auction and the delivery year; economically viable, as indicated by actual merchant entry and competitive costs; and amenable to accurate estimation of its Net CONE.

We recommend shifting the reference resource from the current natural gas-fired combustion turbine (CT) to a natural gas-fired combined cycle (CC) because the CC best meets these criteria in PJM. The CC is clearly economically viable, as it has the largest amount of recent merchant entry and a lower estimated Net CONE than the other candidate resources. CTs continue to be less economic than CCs, consistent with their extremely limited entry in the recent past. Selecting the CT as the reference resource would set the demand curve in a way that would perpetuate excess supply in PJM (although could be considered a way to buy extra reliability insurance for a premium). We considered BESS as a potential source of "clean capacity" for areas with more stringent environmental regulations that could limit the feasibility of developing new natural gas-fired resources. However, its estimated Net CONE is much higher than the CC without there being a clear enough indication at this time that the CC could not be built. We recommend that PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate.

For each resource evaluated, we developed technical specifications of a complete plant reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. The CC specifications are for a 1,182 MW plant with two trains of a single-shift combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two "single-shaft 1x1"s) including 123.9 MW of duct-firing capacity. The CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[1] The CC has a higher-heating value (HHV) average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. CT specifications included a single simple cycle GE 7HA.02 with 367 MW capacity and a 9,189 Btu/kWh full-load average heat rate. BESS specifications are for a 200 MW 4-hour battery with 13% initial oversizing and capacity augmentation planned every 5 years to maintain charge capability and duration.

[1] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

Cost Analysis

For CC and CTs in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. For BESS, we performed a top-down cost analysis based on a less detailed plant design and recent experience estimating costs for developers.

We translate the estimated costs into the net revenues the resource owner would have to earn in its first year to enter the market, assuming a 20-year economic life for the CC and CT and net revenues on average remain constant in nominal terms over that timeframe. We believe these assumptions are reasonable given widespread concern expressed by developers in the stakeholder community that gas-fired generation has limited value beyond the assumed 20-year life in a policy environment that increasingly disfavors greenhouse gas-emitting generation (and even capacity). For the BESS, we assumed a shorter 15-year economic life based on a representative degradation profile and warranty term typical for the selected battery technology.

To estimate the net revenue the reference resource would need to earn to achieve the required return on and return of capital, we estimated the cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.

Table ES-1 below shows the resulting 2026/27 CONE estimates for CCs for each CONE Area. The CONE values are 56% higher (or $180/MW-day ICAP) than PJM's 2022/23 values from the 2018 CONE Study, averaged across all four CONE Areas. Three factors explain this increase:[2]

- Declining Bonus Depreciation**:** Bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $25/MW-Day (ICAP) to CONE.
- Cost Escalation: The costs of materials, equipment, and labor have escalated and will continue to escalate at a faster rate than expected at the time of the last study. These cost increases add $92/MW-Day (ICAP) to CONE, relative to the 2022/23 estimate.

[2] These factors add to more than $180/MW-day (ICAP) due to offsets from a slightly lower cost of capital that reduces CONE by $4/MW-day (ICAP).

- Plant Design Changes: The use of dry-cooling, building a gas-only plant (without dual fuel capability) with firm gas transportation contracts under more constrained environmental permitting regimes (along with smaller increases from 2x1 to double-train 1x1 CCs) adds $66/MW-Day (ICAP).

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

There is considerable uncertainty in the development of the estimated CONE values for the reference resources, particularly regarding volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, and the costs could be greater still if technologies are more constrained by environmental regulations. For BESS, the uncertainty in levelized costs is even greater because of rapidly-changing cost of equipment, currently unresolved applicability of tax credits, and other complications if combined into hybrid plants (and even greater uncertainty with E&AS offsets).

E&AS Methodology

We continue to recommend using a forward-looking E&AS offset, as described in our 2020 testimony and as PJM implemented for its 2022/2023 capacity auction. This approach reflects future market conditions that developers face and avoids distortions from anomalous conditions in a backward-looking approach. We recommend continuing to use the same liquid hubs for natural gas and electricity, and scaling ancillary services prices to energy prices. We recommend that PJM should not include regulation revenues in its estimation of the E&AS offset since the market for regulation is too small to provide substantial additional revenue to capacity entering the PJM market at scale. These recommendations all apply equally to the CT, along with a recommended 10% increase in the estimated day-ahead gas costs to account for having to buy gas in the less liquid intraday market when committed in the real-time market. For BESS, we recommend using the same forward prices along with a virtual dispatch as PJM has been performing with the PLEXOS model.

Application of this forward methodology to CCs leads to indicative E&AS offset values for the CC of $209/MW-day for the RTO, $222 for MAAC, $189 for EMAAC, and $249 for SWMAAC (all denominated in 2026 dollars per UCAP MW-day). This is about $10-30/MW-day greater than the values used for MOPR reviews for the 2022/23 auction, with inflation more than offsetting other factors that tend to decrease the E&AS offset.

Implications for Net CONE and VRR Curve

Elevated Net CONE. With substantially higher CONE and only slightly higher indicative E&AS offsets, indicative CC Net CONE is correspondingly higher, at $307/MW-day for the RTO, $294 for MAAC, $329 for EMAAC, and $257 for SWMAAC (all denominated in 2026 dollars and UCAP MW). This is about $154 higher than CC Net CONE for 2022/23; it is similarly above recent capacity market clearing prices when new CCs entered, and this is consistent with cost escalation, more constrained plant designs, and tax laws; plus likely increased reluctance to invest given a regulatory and market environment that is increasingly favoring clean energy.

Slightly elevated VRR Curve. In spite of significant cost increases, updated CC Net CONE is only $47/MW-day higher than CT Net CONE for 2022/23, since CCs are more economic than CTs. Inefficiently maintaining the CT as the reference resource would increase Net CONE by much more. Thus, switching the reference resource to CCs would moderate the increase and should support procuring reserves closer to target.

Heightened Uncertainty. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we tested robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

I. Introduction

I.A. Background

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which the Variable Resource Requirement (VRR) curve sets the "demand" for capacity. The VRR curve is designed primarily to procure sufficient capacity for maintaining resource adequacy according to traditional standards. The longstanding resource adequacy objectives are to avoid supply shortages in expectations all but once in ten years system-wide (i.e., Loss of Load Expectation or LOLE of 0.1 events/yr), with no more than 0.04 LOLE incremental risk in the Locational Deliverability Areas (LDAs). With probabilistic modeling conducted by PJM, these objectives are translated into Reliability Requirements expressed in terms of megawatts of unforced capacity (MW UCAP).

The VRR curves are centered approximately on a target point corresponding to the Reliability Requirements, at a price given by the estimated long-run marginal cost of capacity, termed the "Net Cost of New Entry (Net CONE)." Rather than a vertical line, the VRR is a curve with nonzero demand above the target to recognize the value of incremental capacity, and with a slope to help mitigate price volatility (as addressed in a separate VRR Curve Study report we are publishing concurrently with this report).

For the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would be willing to enter the market if needed. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would require (in combination with its expected net revenues from the energy and ancillary services markets) to recover its capital and fixed costs, given reasonable expectations about future cost recovery. Thus, Net CONE is given by gross CONE minus the projected Energy and Ancillary Services revenue (E&AS Offset).

Following its tariff, PJM has traditionally estimated Net CONE for a new gas-fired combustion turbine (CT) entering in each of four CONE Areas.[3] Gross CONE values have been determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[4] Shortly before each Base Residual Auction, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction.

PJM also develops Net CONE estimates for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[5] This has less relevance than in past since PJM filed and FERC accepted a revision to MOPR rules that limit its applicability.

I.B. Study Objective and Scope

PJM retained consultants at The Brattle Group and Sargent & Lundy to assist PJM and stakeholders in its quadrennial review. Per the PJM tariff, the scope of the Quadrennial Review is to review the VRR curve and its parameters, including the Cost of New Entry and the E&AS Offset methodology. To that end, a separate, concurrently issued report addresses the shape of the VRR curve. This report:

- Develops CONE estimates for new CT and CC plants and one “clean technology” in each of the four CONE Areas for the 2026/27 Base Residual Auction (BRA) and proposes a process to update these estimates for the following three BRAs;
- Reviews the E&AS offset methodology
- Recommends the most appropriate reference resource whose cost will best indicate the price at which developers would be willing to add capacity.

To estimate CONE for each resource type, we aim to represent the plant configuration, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, not unique sites with unusual characteristics. We estimate costs by specifying the

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[3] The four CONE Areas are: CONE Area 1 (EMAAC), CONE Area 2 (SWMAAC), CONE Area 3 (Rest of RTO), and CONE Area 4 (WMAAC). PJM reduced the CONE Areas from five to four following the 2014 triennial review and incorporated Dominion (formerly CONE Area 5) into the Rest of RTO region.

[4] PJM 2017 OATT, Section 5.10 a.

[5] PJM 2017 OATT, Section 5.14 h.

reference resource and site characteristics, conducting a bottom-up analysis of costs, and translating the costs to a first-year CONE.

We provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of CONE, but also inform the range of uncertainty, a key consideration in designing the VRR curve, as discussed in our separate report.

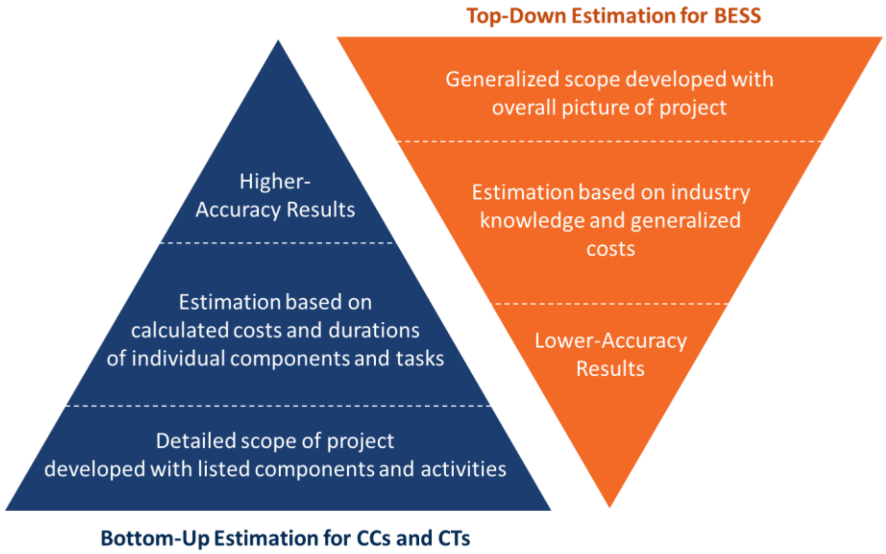
I.C. Analytical Approach

Our starting point is to identify the most appropriate technology to serve as the reference resource for the VRR curve. As discussed in Section II, we identified criteria for selecting the reference resource then evaluated a broad range of resource types against those criteria in an initial screening analysis. This narrowed the choices to a CC, a CT, and BESS, for each of which we analyzed the costs more extensively further—and ultimately recommended using the CC as the reference resource for all locations.

For each of the three identified resources, we estimated CONE for the four CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant characteristics and site characteristics based on: (1) our analysis of the predominant practices of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. Our analysis for selecting plant characteristics for each CONE Area is presented in Section 0 of this report.

We developed comprehensive, bottom-up cost estimates of building and maintaining the reference CC and CT in each of the four CONE Areas. To present a reasonable order-of-magnitude cost estimate for the BESS, we utilized a generalized, top-down approach. Figure 1 describes the attributes of each approach.

FIGURE 1: ATTRIBUTES FOR BOTTOM-UP AND TOP-DOWN ESTIMATION METHODS



Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on developers' long-term market view and how this long-term market view impacts the expected cost recovery path for the plant—specifically whether a plant built today can be expected to earn as much in later years as in earlier years.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Reference Resource Selection

The purpose of selecting a reference resource and developing administrative Net CONE estimates is only to set a VRR curve that aims to procure enough resource adequacy credits. The choice of reference resource does not dictate which resources will enter the market. The administrative Net CONE value does not determine capacity prices; long-run prices depend primarily on the supply curve. Still, as the VRR curve is likely to remain sloped and anchored on our estimate of Net CONE, we aim to estimate Net CONE as accurately as possible, and that starts with a choice of the reference resource.

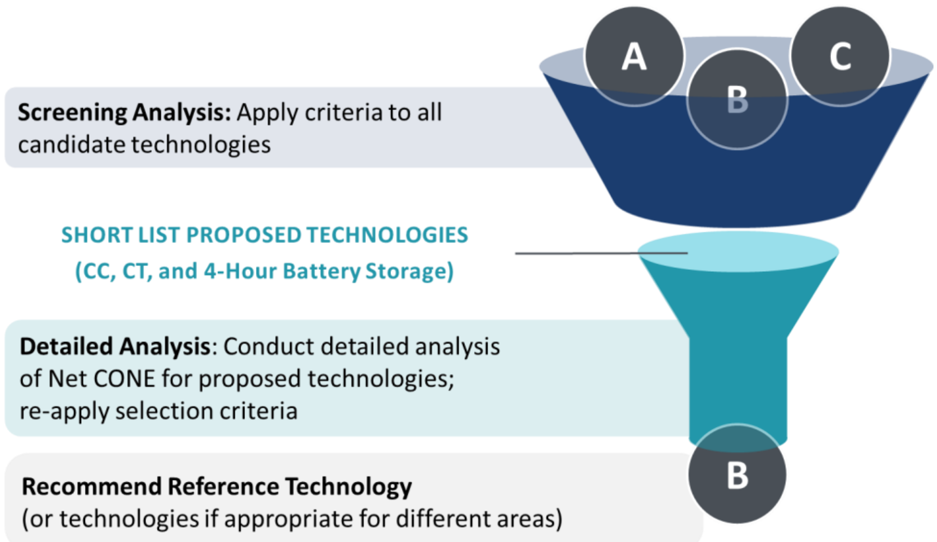
PJM has always used a reference resource, specifically a CT, to estimate Net CONE but asked us to evaluate its continued suitability for representing the cost at which suppliers are willing to bring significant amounts of capacity to PJM. We also considered CCs and a range of other technologies, including BESS as a possible "clean technology" for areas with more stringent environmental regulations. Finally, we also considered the possibility of relying on "empirical Net CONE," i.e. the price at which suppliers have willingly offered new capacity into recent auctions, rather than identifying a specific technology and estimating its net cost for future entry into the market. All possibilities were evaluated against a set of criteria for meeting RPM objectives.

In order to meet RPM reliability objectives with least risk of procuring far above or below target, we recommend switching to a CC as the reference resource. This aligns the VRR curve with observed entry of a technology that is feasible and most economic to build on a merchant basis, and whose Net CONE can be estimated relatively accurately. By contrast, CTs are not being built and are estimated to cost 20% more, on net, for capacity. Other technologies are similarly less economic or otherwise did not meet our selection criteria. Even in areas with more stringent environmental regulations, we did not identify a clear need to adopt a non-emitting reference resource at this time. Finally, empirical Net CONE is a useful benchmark but is not directly suitable because it does not reflect current market conditions affecting the costs of materials, equipment, and labor, nor the regulatory outlook that affects the design of the resources and their future revenue recovery.

II.A. Process for Selecting Reference Resource

We conducted the analysis in several steps, as shown in Figure 2 below. First, we developed criteria for choosing a reference resource; second, we identified a broad range of technologies to evaluate at a high-level against those criteria, resulting in a short list for detailed cost and E&AS analysis; finally, we applied the selection criteria again to select the single most appropriate technology to serve as the reference resource, reflecting the updated net costs of those resources.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS



In consultation with PJM and its stakeholders, we developed the reference resource selection criteria. The foundational objective of the selection criteria was to identify the resource that best supports the RPM's broader objective of procuring enough capacity to meet resource adequacy goals. Given that, we developed three selection criteria.

The first and most basic of these criteria is that the resource has to be feasible to build in the (slightly more than) three-year timeframe between the Base Residual Auction and the Delivery Year, so that high clearing prices in an auction can draw in potential projects when needed/economic.

The second criterion is that the resource must be an economic source of incremental capacity. Otherwise, anchoring the VRR curve on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and lower estimated Net CONE, and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review. The reason for focusing on merchant entrants is partly to ensure that the VRR curve is set high enough to attract merchant entry in the future. It is also to avoid including policy-supported payments (such as renewable energy credits, or RECs) in the E&AS Offset, since such payments are difficult to assess absent broad competitive markets and are limited to the amount of capacity that the policy is intended to achieve. Moreover, such an exercise would suffer from circularity since the necessary level of policy payments needed to support target reasons are in part set by capacity price itself.

The third criterion is that the resource's Net CONE can be estimated accurately. If Net CONE is mis-estimated, the VRR curve will procure more or less capacity than desired. Accurate estimation depends on the certainty of plant designs and their costs and the ability to estimate E&AS offsets using market data. It also depends on the scalability of a standardized resource, not subject to rapid increases in costs as the best sites are exhausted, in which case the cost would depend strongly on penetration. Finally, estimation accuracy also depends on the capacity rating of resources relative to their nameplate. Lower ratings (i.e., low ELCC) magnify the effect of estimation errors on the cost per qualified MW.

Figure 3 summarizes these criteria and sub-criteria for evaluating each candidate resource type.

FIGURE 3: REFERENCE RESOURCE SELECTION CRITIERIA

Feasible to build for the delivery year, given local laws/regulations and technical factors

Economic source of incremental capacity
- Demonstrated by recent merchant entry, not in anomalous situations
- Not having a Net CONE much higher than other candidates
- Likely to remain economic through the end of the review period (2029/30)

Costs, net E&AS revenues, and RA contribution per MW can be assessed accurately
- Evidence of capital and operating costs exists from commercial experience
- Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
- Has stable UCAP/ICAP ratio or ELCC, rather than changing steeply with penetration or fleet composition
- Has high UCAP/ICAP ratio or ELCC, else uncertainties are amplified per kW UCAP
- Not largely dependent on revenues that are difficult to forecast (AS, energy volatility, RECs)

II.B. Evaluation of Candidates against Criteria

The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems (BESS), hybrid photovoltaic (PV)-BESS, utility-scale PV, onshore wind, energy efficiency and demand response, uprates/conversions, and emerging technologies. Screening each of these against the evaluation criteria was straightforward in most cases, as shown in Table 1 below. For example, wind resources currently are not entering as a merchant resource without policy support in PJM, corresponding to its relatively high costs, and its Net CONE would be difficult to assess accurately due to its low ELCC rating that magnifies cost estimation errors. Energy efficiency, DR, and uprates/conversions were eliminated because of highly non-uniform costs across measures and sites, and scalability challenges with any particular type of measure.

TABLE 1: INITIAL REFERENCE RESOURCE SCREENING ANALYSIS

Technology	Feasible to Build for DY	Economic Source of Capacity	Accuracy of Net CONE Estimates	Screening Decision
Gas CC	Yes	Yes	High	Consider as leading candidate
Gas CT	Yes	Unclear (few built, higher Net CONE)	High	Consider for further analysis
Battery Storage	Yes	Unclear (not standalone cleared in RPM)	Medium (falling costs; AS-dependence; ELCC stability?)	Consider for further analysis
Hybrid PV-BESS	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Utility-Scale PV	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Wind	Yes	Unclear (is any entering as merchant?)	Low (REC-dependence; low ELCC, stability)	Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR
Energy Efficiency/ DR	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Uprates/ Conversions	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Emerging Technologies	No	None	Low	Eliminate: Infeasible to build

Based on stakeholder feedback, we included one non-emitting resource in our CONE and E&AS analysis, selecting BESS due to its lower uncertainty in accurately estimating its Net CONE value compared to utility-scale solar PV and hybrid PV-BESS. Utility-scale solar PV ELCC values are highly uncertain as they decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV investments in PJM depend on RECs, the price of which is uncertain, which increases Net CONE uncertainty; REC prices also depend on capacity prices, creating a circularity that confounds estimating the capacity price at which PVs will enter. Hybrid PV-BESS resources are similarly uncertain as utility-scale solar PV in terms of the ELCC value and dependence on RECs for entry, plus the additional uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

That left CC, CT, and BESS as finalists. Ultimately, CCs best met the selection criteria, as summarized in Table 2 below. They are the most economic and are being built by developers. CTs continue not to be built, consistent with our estimate that their RTO Net CONE is about 20% higher than the CC, as shown in this report. In addition, CC Net CONE can be estimated relatively accurately. The conventional wisdom used to be that CCs are subject to more estimation error in E&AS Offsets, since their E&AS Offsets are larger. We disagree. The benchmark for “accuracy” should be the value that investors anticipate in the market. That benchmark is not directly observable, but there is more market data available to anticipate E&AS Offsets for CCs than CTs. CCs’ net E&AS revenues can be fairly accurately approximated assuming 5x16 operation and applying observable futures prices for 5x16 on-peak blocks. No such benchmark is available for CTs that run less frequently when prices spike, so we rely on historical estimates that may not be representative of the future delivery year due to historical anomalies and evolving market conditions. Finally, CTs face less transparent gas procurement costs since they are committed and dispatched day-of.

TABLE 2: BASIS FOR SELECTING THE RECOMMENDED REFERENCE RESOURCE

Technology	Feasible to Build for Delivery Year	Economic Source of Capacity	Accuracy of Net CONE Estimates
Gas CC	**Yes**	**Yes** (significant recent entry; lowest 2026/27 Net CONE)	**Highest**
Gas CT	**Yes** (may be infeasible to build in NJ)	**Unclear** (few recently built; Net CONE 20% higher than CC)	**High** (higher forward E&AS uncertainty due to lack of forward pricing matching CT dispatch)
Battery Storage	**Yes**	**Unclear** (no cleared capacity to date; highest 2026/27 Net CONE among candidates)	**Low** (uncertain future AS revenues; falling costs)

We also considered “empirical Net CONE” based on the clearing price at which new capacity has proven willing to enter in the past several auctions. Historical data do indeed provide a useful reference point for Net CONE, although we rejected using it directly because it is backward-looking at a time when fundamentals are changing profoundly due to cost escalation and clean energy policies.

III. Natural Gas-Fired Combined-Cycle Plants

III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

[6] For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

[7] The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

CONE Area	Elevation	Max. Summer Temperature	Relative Humidity
	(ft)	*(°F)*	*(%RH)*
1 EMAAC	330	92.2	55.3
2 SWMAAC	150	96.2	44.2
3 Rest of RTO	990	89.9	49.7
4 WMAAC	1,200	91.4	48.9

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

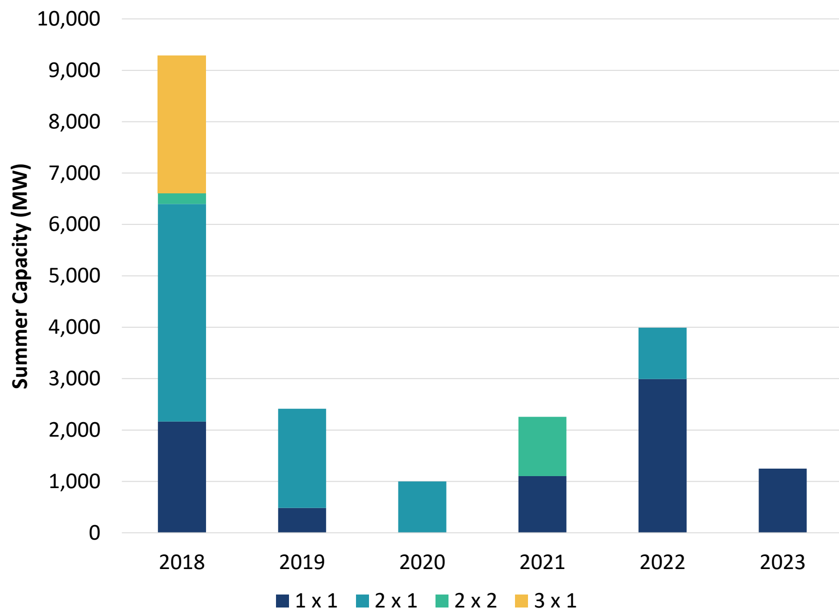
Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 1174 / 1144 / 1133*
Net Heat Rate (HHV in Btu/kWh)	
without Duct Firing	6365 / 6383 / 6359 / 6368*
with Duct Firing	6602 / 6619 / 6593 / 6601*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018



Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Number of Trains	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*	2023 *(MW)*	Total Capacity *(MW)*	Capacity Share *(%)*
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

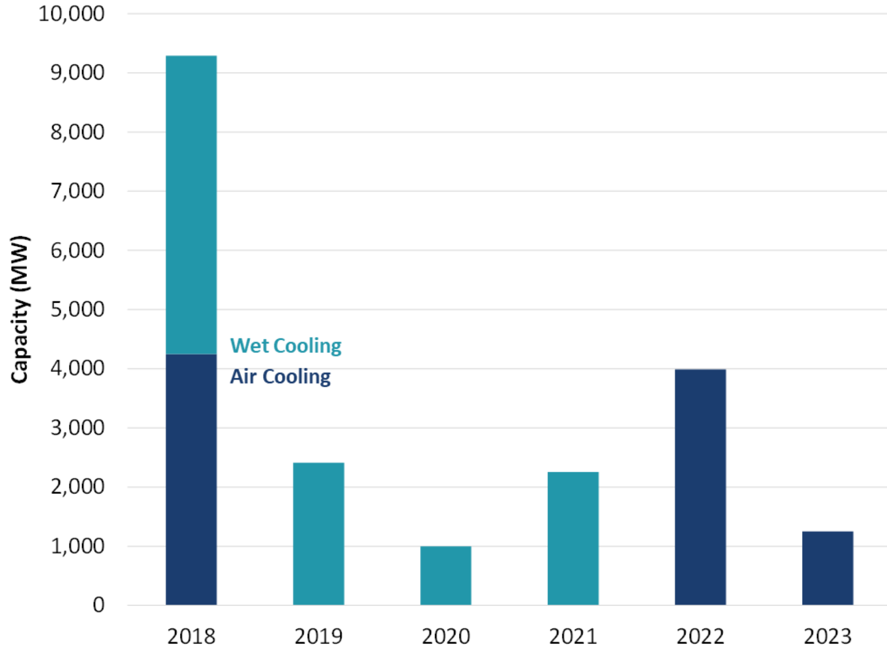
III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize "wet" cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

[8] PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

FIGURE 5: COOLING SYSTEM FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

III.A.3. Emissions Controls

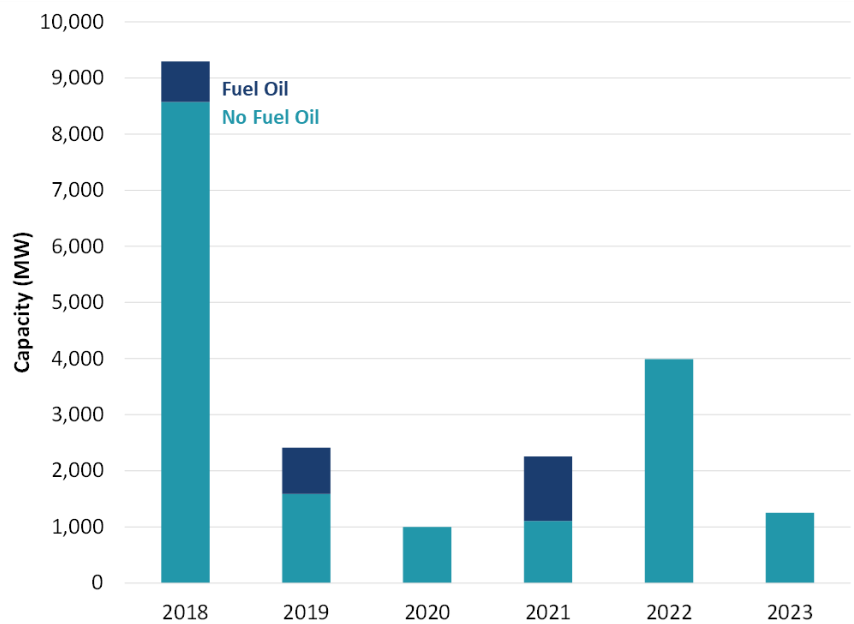
The reference CC is assumed to utilize selective catalytic reduction (SCR) systems as a nitrogen oxide (NOx) emissions control technology and CO catalyst systems as a carbon monoxide (CO) emissions control technology. The SCR system and CO catalyst adds an incremental cost of $72 million (in 2021 dollars) to the capital costs. A more detailed discussion of emissions controls can be found in the 2018 PJM CONE study.

III.A.4. Fuel Supply

Natural gas-fired plants can be designed to operate solely on gas or with "dual-fuel" capability to burn either gas or diesel fuel oil. Dual-fuel plants can switch to oil when gas becomes unavailable or prohibitively costly due to pipelines becoming fully utilized and congested. Plants without dual-fuel capability can ensure access to their fuel supply through firm transportation contracts, although such contracts cost more than dual-fuel capability in most locations.[9]

Developers have moved away from installing dual-fuel capability on new CCs. Figure 6 below shows that only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel since 2018; data from PJM confirms that almost all are instead firming their availability with firm gas transportation contracts.

FIGURE 6: DUAL-FUEL CAPABILITY FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted).

Instead, we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2016/2017 BRA obtain firm transportation service to ensure adequate fuel supply.[10] Based on these trends, we updated our assumption from the

9 Eastern Interconnection Planning Collaborative, "Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives," accessed September, 2017, http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

10 PJM provided the fuel supply arrangements for 20,848 MW of new gas plants that first cleared the capacity market in the 2016/2017 BRA to the 2020/2021 BRA, including firm transportation, dual fuel capability, and installing gas laterals to multiple pipelines.

2018 PJM CONE study for the CC reference resource to obtain firm gas supply across all CONE areas.[11] The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs in the following section.

III.B. Capital Costs

Plant capital costs are costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2021 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix A.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost for an online date of June 1, 2026 by escalating the 2021 costs using escalation rates provided by Sargent & Lundy. The 2026 "installed cost" is the present value of the construction period cash flows as of the end of the construction period, using the monthly drawdown schedule and the cost of capital for the project.

Based on the technical specifications for the reference CC described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 6 below. The maximum variation between overnight capital costs between CONE areas is $100/kW, similar to the $94/kW from the 2018 PJM CONE study. The methodology and assumptions for developing the capital cost line items are described further below.

[11] We recommended in the 2018 PJM CONE study dual-fuel capabilities in all CONE Areas except SWMAAC. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

TABLE 6: PLANT CAPITAL COSTS FOR CC REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1171 MW*	*1174 MW*	*1144 MW*	*1133 MW*
Owner Furnished Equipment				
Gas Turbines	$155.3	$155.3	$155.3	$155.3
HRSG / SCR	$80.7	$80.7	$80.7	$80.7
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$320.7**	**$320.7**	**$320.7**	**$320.7**
EPC Costs				
Equipment				
Other Equipment	$86.3	$86.3	$86.3	$86.3
Construction Labor	$365.5	$283.3	$297.1	$330.5
Other Labor	$75.5	$69.0	$70.1	$72.7
Materials	$75.5	$75.5	$75.5	$75.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$98.5	$89.6	$91.1	$94.7
EPC Contingency	$108.4	$98.6	$100.2	$104.2
Total EPC Costs	**$871.4**	**$763.9**	**$782.0**	**$825.6**
Non-EPC Costs				
Project Development	$59.6	$54.2	$55.1	$57.3
Mobilization and Start-Up	$11.9	$10.8	$11.0	$11.5
Net Start-Up Fuel Costs	-$13.9	-$14.0	-$9.8	-$13.5
Electrical Interconnection	$25.3	$25.4	$24.7	$24.5
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$2.2	$1.8	$1.0	$1.8
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$6.0	$5.4	$5.5	$5.7
Owner's Contingency	$10.0	$9.4	$9.7	$9.7
Emission Reduction Credit	$2.3	$2.3	$2.3	$2.3
Financing Fees	$29.2	$26.7	$27.2	$28.1
Total Non-EPC Costs	**$166.4**	**$155.8**	**$160.6**	**$161.3**
Total Capital Costs	**$1,358.5**	**$1,240.5**	**$1,263.3**	**$1,307.6**
Overnight Capital Costs ($million)	**$1,359**	**$1,240**	**$1,263**	**$1,308**
Overnight Capital Costs ($/kW)	**$1,160**	**$1,057**	**$1,104**	**$1,154**
Installed Cost ($/kW)	**$1,255**	**$1,144**	**$1,195**	**$1,248**

III.B.1. EPC Capital Costs

III.B.1.i. Project Developer and Contract Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

III.B.1.ii. **Equipment and Materials**

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines. The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. We assume all purchases for plant equipment are exempt from sales tax.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

III.B.1.iii. **Labor**

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Similar to the 2018 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region in 2021, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix A.

III.B.1.iv. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to the Owner Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Capital cost estimates include an EPC contractor fee of 10% of total EPC and OFE costs for CC facilities based on S&L's proprietary project cost database.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, including the contractor fee. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.7% to 9.8% of the pre-contingency overnight capital costs.

III.B.2. Non-EPC Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

III.B.2.i. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.ii. Net Startup Fuel Costs

Before commencing full commercial operations, the new CC plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix A.

III.B.2.iii. Emission Reduction Credits

Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as attainment. ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are determined based on the annual NOx and volatile organic compounds (VOC) emissions of the facility and offset ratio which is dependent on the specific plant location. Similar to our assumption from the 2018 PJM CONE study, we assumed a cost of $5,000/ton for all CONE Areas and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2021 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

III.B.2.iv. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. We assume the gas interconnection will require a metering station and a five-mile lateral connection, similar to the 2018 PJM CONE Study. From the data summarized in Appendix A, we estimate that gas interconnection costs will be $29.5 million (in 2021 dollars) based on $5.1 million/mile and $4.0 million for a metering station. Similar to the 2011, 2014, and 2018 PJM CONE studies, we found no relationship between pipeline width and per-mile costs in the project cost data.

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using recent project data provided by PJM with the online service year between 2018 and 2021, we selected 17 projects (3,700 MW of total capacity) that are representative of interconnection costs for a new gas CCs and calculated a capacity-weighted average electrical interconnection cost of $18.9/kW (in 2021 dollars) for these projects, 5% lower than the 2018 PJM CONE Study. The estimated electric interconnection costs are between $21.4 and $22.2 million for CCs (in 2021 dollars). Appendix A presents additional details on the calculation of electric interconnection costs.

III.B.2.v. **Land**

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We assume that 60 acres of land are required for the CC. Table 7 shows the resulting costs (see Appendix A for more detail).

TABLE 7: COST OF LAND PURCHASED FOR REFERENCE CC

CONE Area	Land Price *($/acre)*	Plot Size Gas CC *(acres)*	Cost Gas CC *($m)*
1 EMAAC	$36,600	60	$2.20
2 SWMAAC	$29,500	60	$1.77
3 Rest of RTO	$16,400	60	$0.98
4 WMAAC	$30,600	60	$1.84

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

III.B.2.vi. **Non-Fuel Inventories**

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel inventories are 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.vii. **Owner's Contingency**

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

[12] The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

2026.[13] The real escalation rate for each cost category was then added to the assumed inflation rate to determine the nominal escalation rates, as shown in Table 8.

TABLE 8: CC AND CT CAPITAL COST ESCALATION RATES (% PER YEAR)

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.00%	2.91%
Labor	1.60%	4.51%

Sources and notes: Escalation rates on equipment and materials costs are derived from the BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from the current overnight costs to the month they would be incurred using the monthly capital drawdown schedule developed by S&L for an online date in June 2026.

We escalated several cost items in a different manner:

- Land: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2026 online date, the land is thus assumed to be purchased in late 2022 such that current estimates are escalated 1 year using the long-term inflation rate of 2.9%.
- Net Start-Up Fuel and Fuel Inventories: no escalation was needed as we forecasted fuel and electricity prices in 2026 dollars.
- Electric and Gas Interconnection: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior to completion, consistent with the 2018 PJM CONE Study; the interconnection costs have been escalated specifically to these months.
- Emission Reduction Credits: escalated to the online start date of June 2026 using the long-term inflation rate of 2.91%.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2026 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate

[13] The near-final CONE results presented on March 25, 2022 assumed an inflation rate of 2.0%.

the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

III.C. Operations and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including contracted services, property tax, insurance, labor, maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated *variable* O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations.

III.C.1. Summary of O&M Costs

Table 9 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2026.

TABLE 9: O&M COSTS FOR CC REFERENCE RESOURCE

	CONE Area			
O&M Costs	**1 EMAAC** *1171 MW*	**2 SWMAAC** *1174 MW*	**3 Rest of RTO** *1144 MW*	**4 WMAAC** *1133 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.8	$0.8	$0.8	$0.8
Labor	$5.2	$5.6	$4.0	$4.1
Maintenance and Minor Repairs	$6.6	$6.7	$6.0	$6.1
Administrative and General	$1.4	$1.4	$1.2	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.2
Property Taxes	$3.0	$16.4	$9.5	$2.9
Insurance	$8.2	$7.4	$7.6	$7.8
Firm Gas Contract	$10.0	$12.4	$16.4	$14.5
Working Capital	$0.2	$0.1	$0.1	$0.1
Total Fixed O&M (2026$ million)	**$36.8**	**$52.6**	**$46.8**	**$38.8**
Levelized Fixed O&M (2026$/MW-yr)	**$31,500**	**$44,900**	**$40,900**	**$34,200**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	0.76	0.76	0.77	0.77
Total Variable O&M (2026$/MWh)	**2.08**	**2.07**	**2.12**	**2.14**

III.C.2. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

III.C.2.i. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, we include the monthly payments specified in the LTSA as fixed O&M costs and the larger costs associated with run-time and starts as variable O&M.

III.C.2.ii. Insurance and Asset Management Costs

We estimate insurance cost of 0.6% of the overnight capital cost per year, from the 2018 PJM CONE study based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of natural gas-fired plants in operation.

III.C.2.iii. Property Tax

We maintained our bottom-up approach for estimating property and personal taxes from the 2018 PJM CONE study. We researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states.[14] The tax rates assumed for each CONE Area are summarized in Table 10 with additional details in Appendix A.

[14] See the 2018 PJM CONE study for a detailed discussion on our bottom up approach.

TABLE 10: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

	Real Property Tax	Personal Property Tax	
	Effective Tax Rate	Effective Tax Rate	Depreciation
	(%)	*(%)*	*(%/yr)*
1 EMAAC			
New Jersey	3.8%	n/a	n/a
2 SWMAAC			
Maryland	1.1%	1.3%	3.30%
3 RTO			
Ohio	1.9%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	2.7%	n/a	n/a
4 WMAAC			
Pennsylvania	3.8%	n/a	n/a

Sources and notes: See Appendix A for additional detail on inputs and sources.

We assume that assessed value of real property will escalate in future years with inflation. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years.

III.C.2.iv. Working Capital

Based on our approach in the 2018 PJM CONE study, we estimate the costs of maintaining the working capital requirement assuming that the working capital requirement is approximately 0.5% of overnight costs and a borrowing rate for short-term debt of 2.1%.[15]

III.C.2.v. Firm Transportation Service Contracts

We maintained our approach for estimating firm transportation service contracts from the 2018 PJM CONE study for the SWMAAC CONE Area for the reference CC. However, we utilized the reservation and usage charges for pipelines servicing EMAAC, Rest of RTO, and WMAAC under FT-1 rate schedules. Table 11 summarizes the pipelines we assumed for each CONE area and the representative firm gas capacity costs. We assume the reference CC commit to procuring firm gas transportation on an annual basis.

[15] 15-day average 3-month bond yield as of January 31, 2022, BFV USD Composite (BB), from Bloomberg.

TABLE 11: CONE AREA PIPLEINES AND FIRM GAS CAPACITY COSTS

	CONE Area	Pipelines	Representative Firm Gas Capacity Cost *(2026$ per Dth/d per Mth)*
1	**EMAAC**	Transco Zone 6 (non-NY), Transco Zone 6 (NY)	$4.50
2	**SWMAAC**	Dominion Cove Point	$5.56
3	**Rest of RTO**	Chicago, Columbia-Appalachia TCO, Dominion South, Michcon, Transco Zone 5	$7.54
4	**WMAAC**	Tennessee 500L, TETCO M3	$6.73

To estimate the costs of acquiring firm transportation service for SWMAAC we escalated the Cost of Firm Gas Capacity per Month of $4.96 (2022$ per Dth/d) from the 2018 PJM CONE study by 2.9% annually to 2026. For the EMAAC, Rest of RTO, and WMAAC CONE Areas, we combined the reservation and usage rates, resulting in a tariff rate for each pipeline. Then the pipeline tariff rates are averaged and escalated by 2.9% annually to 2026 by CONE area to calculate the representative firm gas capacity. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix A.

III.C.3. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. As discussed above, we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.

III.C.4. Escalation to 2026 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 8) have been used to escalate the O&M costs. The assumed real escalation rate for O&M line items that are primarily labor-based is 1.6% per year, while those for other O&M costs remain constant in real terms.

III.D. Financial Assumptions

III.D.1. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[16] Consistent with our approach in previous CONE studies, we developed our recommended cost of capital by an independent estimation of the ATWACC for publicly-traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from recent merger and acquisition transactions.[17] Based on our empirical analysis as of March 31, 2022, we recommend 8.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2026 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, cost of debt 4.7%, a combined federal and state tax rate of 27.7%, and return on equity (ROE) of 13.6%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and ROE do not significantly affect the CONE calculation as long as they amount to the empirically-based 8.0% ATWACC.[19] This is because the CONE value is determined by the 8.0% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

As a point of reference, we compare our current ATWACC recommendation to recommendations in our prior PJM CONE studies in Figure 7. The red circles (35% federal tax rate for 2011 and

[16] The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

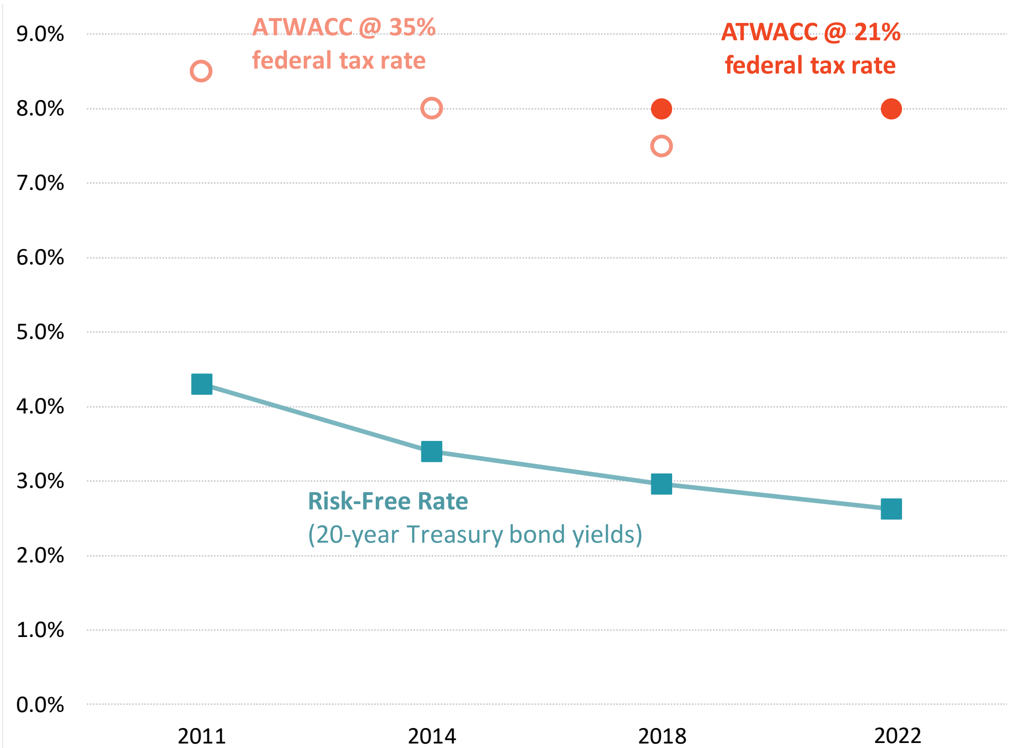
[17] Supplementing our ATWACC analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours.

[18] 4.7% × 55% × (1 – 27.7%) + 13.6% × 45% = 8.0%. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes (= 8.5% + (1 – 8.5%) × 21%). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

[19] Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

2014) and dots (21% tax rate for 2018 and 2022) represent the recommended ATWACCs, and the line is the prevailing risk-free rate (20-year Treasury rate).

FIGURE 7: COMPARISON OF BRATTLE ATWACC RECOMMENDATIONS FOR PJM



Sources: 2011, 2014, and 2018 values based on previous PJM CONE studies.

Over the last decade, our recommended ATWACC of merchant generation was 8.5% in 2011, then dropped and stayed at 8% between 2014 and 2022. These changes are driven by changes in both business risks of the industry, and market risks such as the risk-free rate and corporate income tax rates.

- We lowered the ATWACC from 8.5% to 8% in 2014 because the 20-year Treasury rate dropped from 4.3% in 2011 to 3.4% in 2014.
- The 20-year Treasury rate dropped further in 2018 to 3.0%. However, we kept our ATWACC recommendation at 8%, because the reduction in federal corporate income tax rate, from 35% to 21% starting from 2018, increases the ATWACC.
- The 20-year Treasury rate dropped again in 2022 to 2.6% as of March 2022. However, the top of the ATWACC range from the sample (the business risk of the merchant generation industry) and the additional reference points approximates 8.0% (Figure 8).

In Table 12, we compare our current recommended costs of capital components to those in our prior PJM CONE studies. The changes in the return of equity (ROE) are based on a number of factors: our recommended ATWACC, the federal-state combined tax rate, cost of debt, and the debt/equity ratios.

TABLE 12: COMPARISON OF COST OF CAPITAL RECOMMENDATIONS

Study Year	Tax Rate	Return on Equity	Equity Ratio	Cost of Debt	Debt Ratio	ATWACC
2011	40.5%	12.5%	50%	7.5%	50%	8.5%
2014	40.5%	13.8%	40%	7.0%	60%	8.0%
2018	27.7%	13.0%	45%	5.5%	55%	8.0%
2022	27.7%	**13.6%**	45%	**4.7%**	55%	8.0%

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for U.S. IPPs. Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[20] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

ATWACC for Publicly Traded Companies as of March 31, 2022: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 13 and charted with sensitivities in Figure 8. Base-case estimates are derived from three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 6.3% for AES to 7.6% for NRG. Additional details about the sample and key inputs are discussed next.

[20] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

TABLE 13: BASE-CASE ATWACC - 2022

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$15,862	$17,754	1.10	10.8%	41%	4.3%	6.3%
NRG Energy Inc	BB+	$9,179	$8,202	1.15	11.2%	53%	4.9%	7.6%
Vistra Corp	BB	$10,117	$10,515	1.10	10.8%	47%	5.2%	7.1%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 3/31/2022, millions USD.
[4]: Value Line.
[5]: RFR (2.62%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

Sample: Our sample consists of three companies: NRG, Vistra, and AES. Since 2018, there are no longer any pure-play merchant generation companies in the US. In 2018, Calpine was taken private by a consortium of private investors, and Dynegy was acquired by Vistra. The new Vistra includes both electricity generation and retail electricity supply. In addition, NRG expanded into competitive retail electricity supply. NRG and Vistra do not currently report their operating segments along the generation and retail supply lines of business. Their business mixes in terms of operating profits in 2019 are shown in Table 14.[21] Our sample also includes AES, a diversified global energy company holding assets in both utilities and the construction and generation of electricity. However, its annual financials only disclose its business segments by geography, not by line of business.[22]

TABLE 14: BUSINESS MIX OF NRG AND VISTRA IN 2019

Company [1]	Retail [2]	Generation [3]
NRG	38%	62%
Vistra	8%	92%

[21] NRG changed its segment reporting in 2020 such that the split between power generation and retail is not available.

[22] AES discloses its annual financials for each of its strategic business units: US and Utilities (which covers the United States, Puerto Rico and El Salvador); South America (which covers Chile, Colombia, Argentina and Brazil); MCAC (which covers Mexico, Central America and the Caribbean); and Eurasia (which covers Europe and Asia). Source: The AES Corporation. (December 31, 2019). Form 10-K. https://s26.q4cdn.com/697131027/files/doc_financials/2019/q4/2019-Form-10-K-FINAL.pdf.

Cost of Equity: We estimate the return on equity (ROE) of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 13, the resulting return on equity ranges from 10.8-11.2% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- We estimated the expected risk premium of the market to be 7.46% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[23]
- In Table 13, we use a risk-free rate of 2.62%, a 15-day average of 20-year U.S. treasuries as of March 31, 2022, as the base case. In addition to our base analysis under current market conditions, we also consider the use of forecasted risk-free rates applicable five years from now to estimate the offer of a new merchant entrant that starts operating in 2026. Blue Chip Economic Indicators forecasts a 3.0% yield for 10-year Treasury yields between 2023 and 2026.[24] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.5%, we estimate the 20-year risk-free rate to be 3.5% and use this as a sensitivity analysis, as shown in Figure 8 below.
- We use betas (column [4] in Table 13) reported by Value Line.[25] They are calculated using 2-year weekly returns.

Cost of Debt: In our previous analyses, we estimated the cost of debt (COD) of the sample companies by the average bond yields corresponding to the unsecured senior credit ratings for each company (issuer ratings).[26] The rating-based average yields, based on a sample of similarly-

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[23] Kroll Cost of Capital Navigator 2021, as of February 2022 (arithmetic average of excess market returns over 20-year risk-free rate from 1926-2021).

[24] Blue Chip Economic Indicators (March 2022), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers.

[25] The 3-year period is chosen over the standard 5-year period to limit the period under the new tax law, which went into effect in 2018, and also to limit the period to be post integration of the 2017 Dynegy / Vistra merger and the spinoff of NRG Yield in 2018.

[26] In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

rated long-term (10 plus years) corporate bonds, are generally preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[27]

TABLE 15: COST OF DEBT

Company	S&P Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
AES Corp	BBB-	2.5%	4.3%
NRG Energy Inc	BB+	2.8%	4.9%
Vistra Corp	BB	3.1%	5.2%

However, company-specific CODs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate. This is the case for the merchant generation corporations: the average yields for the BBB-, BB+, and BB rated corporate bonds are barely higher than the current risk-free rate and lower than the Blue Chip forecast for the risk-free rate in 2022 and 2023. In contrast, U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the base-case estimation in Table 13, we use the company-specific bond yield, but in the sensitivity analysis (Figure 8 below) we also use rating-based cost of debt.

Debt/Equity Ratio: We estimate the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg. They are reported in Table 13 above.

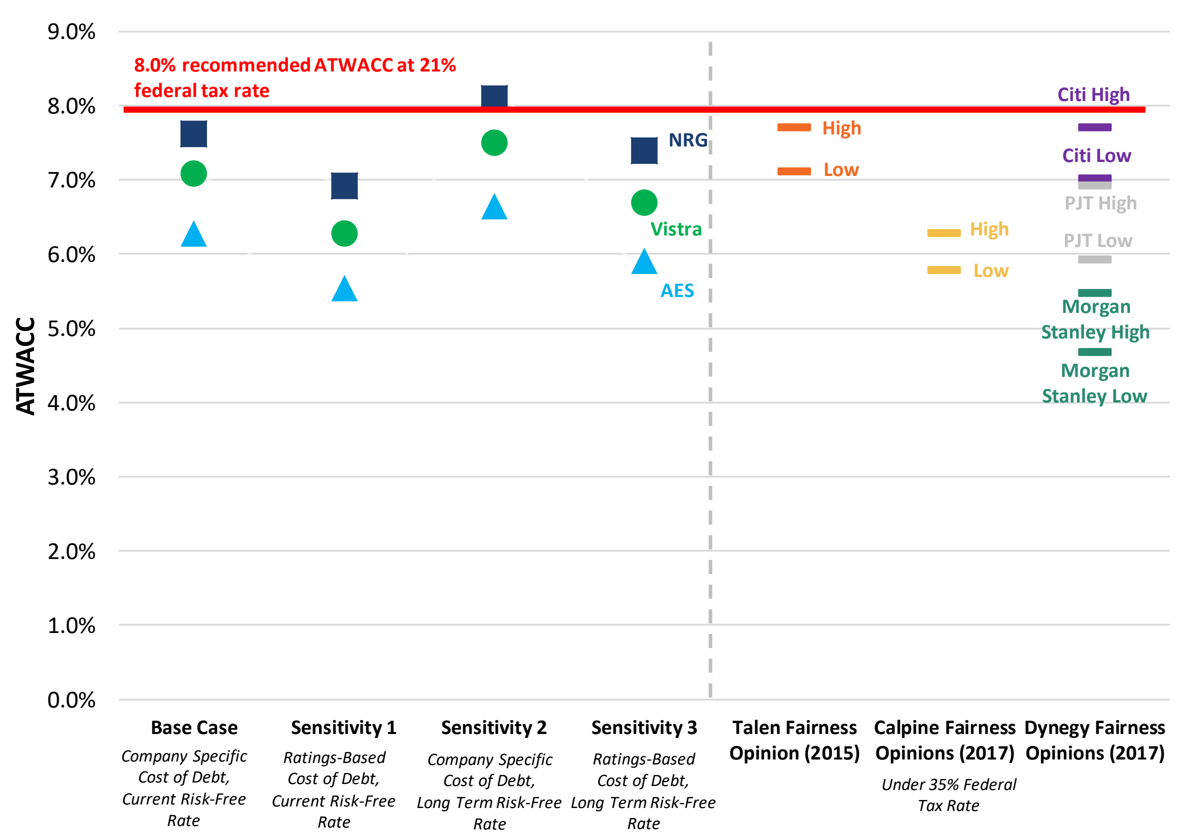
ATWACC Sensitivities and Cost of Capital Benchmarks from Recent Fairness Opinions:
Figure 8 reports the ATWACC for the sample under alternative assumptions for the COD and risk-free rate, along with the discount rates used in fairness opinions (discussed below) as additional reference points:

- *Baseline Case* uses the inputs and results shown in Table 13 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted long-term risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted long-term risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

[27] These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. By construction, these factors tend to be averaged out in the ratings-based average CODs.

For the Base Case and each sensitivity, the colored marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs range from 5.5% (AES) to 6.9% (NRG). Under the other two scenarios when the forecasted risk-free rate is used, the upper ends of the ATWACC approach 8.1% (Sensitivity 2) and 7.4% (Sensitivity 3).

FIGURE 8: SUMMARY OF BASE CASE AND ALTERNATIVE CASES



Additional cost of capital reference points shown on the right side of Figure 8 above come from publicly-available discount rates used by financial advisors and analysts in valuations associated with mergers and divestitures. While there are no details provided on how these ranges were developed, these values still provide useful reference points for estimating the cost of capital. As in our 2018 analysis, we rely on three transactions with publicly-disclosed discount rates, and adjust them for the changes in the risk-free rates between the as of dates of the fairness opinions and March 31, 2022. These three transactions are

- *Acquisition of Talen Energy by Riverstone Holdings*: the disclosed range of discount rate is 6.7% to 7.3%, released in June 2016.[28] Between the fairness opinion date (March 31, 2016)

[28] Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016.

and March 31, 2022, the risk-free rate increased about 0.4%. As a result, the range of 7.1% to 7.7% is shown in Figure 8.

- *Acquisition of Calpine by Energy Capital Partners*: the range of discount rate range disclosed in the June 2017 fairness opinion is 5.75% to 6.25%;[29] this is also the range shown in Figure 8, as the risk-free rates between June 2017 and March 31, 2022 are almost the same;
- *Acquisition of Dynegy by Vistra*: each of the three financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) involved in that transaction used a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citi.[30] This rather wide range of discount rates (4.7% to 7.7%) reflects the uncertainty in cost of capital estimates for the U.S. merchant generation industry. Because the risk-free rates between the fairness opinion dates and March 31, 2022 are almost the same, the originally disclosed range is shown in Figure 8.

We should note that all these acquisitions were announced before the 2018 tax law change, so their discount rates were based on the 35% federal corporate income tax rate. All else equal, the discount rate would be higher under a lower federal income tax rate. In other words, the ranges shown in Figure 8 under-estimates the ATWACC from the transactions under the current 21% tax rate.

ATWACC for Merchant Generators in PJM Markets and the Recommended Components: The appropriate ATWACC for the CONE study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As a pure merchant project in PJM, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts in place.[31] As we have done in previous studies, we make an upward adjustment toward the upper end of the range from the comparable company results to reflect the relatively higher risk of pure merchant operations. Based on the set of reference points shown in Figure 8 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation

[29] Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

[30] Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 25, 2018.

[31] This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

companies, we believe that an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[32]

III.D.2. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal tax rates of 21%. The state tax rates assumed for each CONE Area are shown in Table 16.

TABLE 16: STATE CORPORATE INCOME TAX RATES

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	11.50%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%

Sources and notes: State tax rates retrieved from www.taxfoundation.org. Machinery and equipment for electricity generation are exempt from state sales taxes.

We calculated depreciation for the 2026/27 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2027 can apply 20% bonus depreciation in the first year of service, which decreases CC CONE on average by $10/MW-day relative to no bonus depreciation. The bonus depreciation phases out completely by the following year. Similar to the 2018 PJM CONE study, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for the reference CC to the remaining depreciable costs (*i.e.*, 20% bonus depreciation, 80% MACRS in 2026/27).[33]

To calculate the annual value of depreciation, the “depreciable costs” (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of

32 The weighted average cost of capital (WACC) without considering the tax advantage of debt payments is 8.0%. We report this value because it is comparable to values reported in other recently released CONE studies in ISO-NE and NYISO.

33 Internal Revenue Service (2021), *Publication 946, How to Depreciate Property,* March 3, 2022. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 55% debt and 4.7% COD.

III.E. Economic Life and Levelization Approach

Translating investment costs into annualized costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life, such that the investor recovers capital and annual fixed costs.

For economic life, we recommend continuing the prior assumption of a 20-year economic life. Although new natural gas-fired plants can physically operate for 30 years or longer, developers in the stakeholder community expressed doubt in any value beyond 20 years in the current and projected policy environment. The policy environment is increasingly disfavoring generation resources that emit greenhouse gases. For example, Illinois and New Jersey have passed legislation or are considering regulations to limit the operation of natural gas-fired plants.[34]

We continue to assume "level-nominal" cost recovery with net revenues constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms), based on our prior analysis of the drivers of long-term cost recovery and updated analysis of the long-term trends in gas turbine costs. Clearly, assuming such a steady stream of revenues then terminating them after an assumed 20-year life is a simplification. Our concurrent VRR Report tests the robustness of the recommended VRR curve to an uncertainty range that encompasses different assumptions on cost recovery.

[34] In Illinois, the 2021 Climate and Equitable Jobs Act (CEJA) phases out of privately-owned gas generation by 2045. While the CEJA does not limit the ability of new CCs to enter, alternative ownership structures may be required with public entities to maintain operation over a 20-year economic life. In New Jersey, the Department of Environmental Protection proposed rules in 2021 that would limit CO_2 emissions for new gas generation units to below 860 lbs CO_2/MWh starting in 2025. Despite this proposed rule, the reference CC will be able to meet the emissions requirements.

III.F. CONE Results and Comparisons

III.F.1. Summary of CONE Estimates

The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 17 summarizes our plant capital costs, annual fixed costs, and levelized CONE estimates for the CC reference plants for the 2026/27 delivery year. The level-nominal CONE estimates range from $506/MW-day in WMAAC to $490/MW-day in SWMAAC.

TABLE 17: ESTIMATED CONE FOR CC PLANTS IN 2026/27

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

Sources and notes: CONE values expressed in 2026 dollars and ICAP terms.

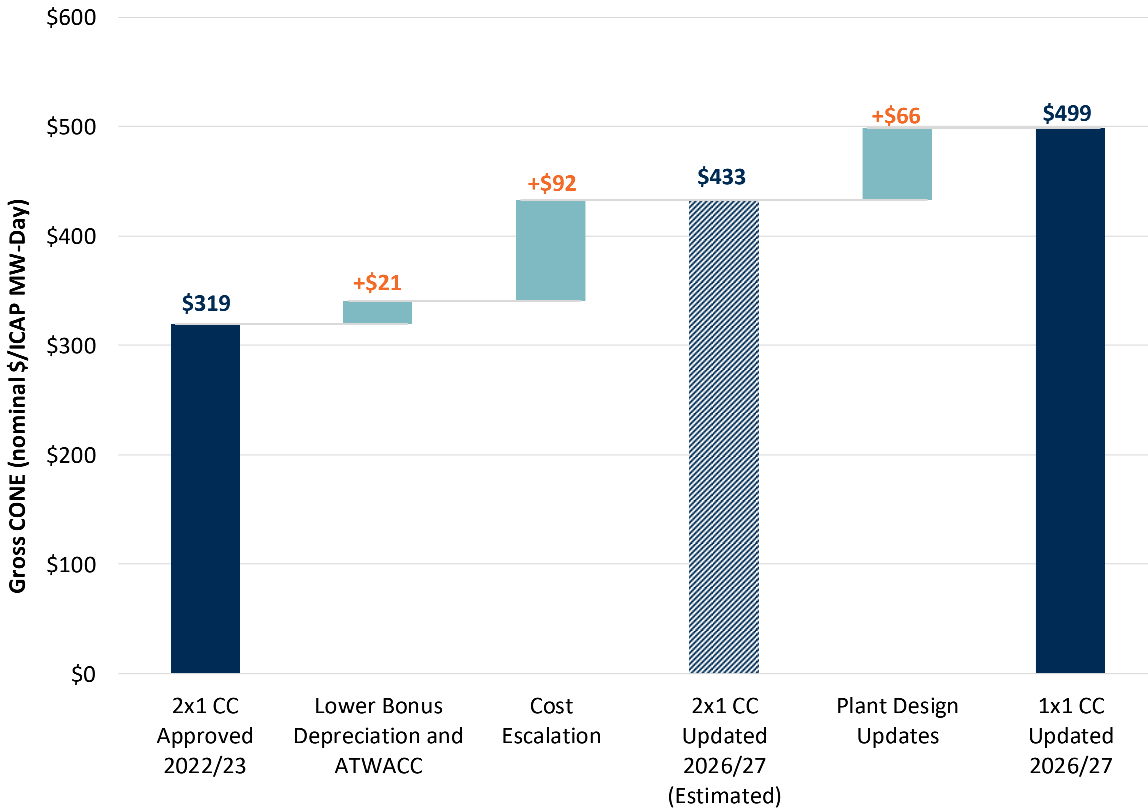
The CC CONE estimates vary slightly by CONE Area, primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

III.F.2. Comparison to Prior CONE Estimates

The 2026/27 CC CONE estimates are considerably higher than the values derived from the 2018 Study that were used (as MOPR parameters) in PJM's Base Residual Auction for the 2022/23

Delivery Year as shown in Figure 9. To explain those increases in terms of individual drivers, we sequentially estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, plant design updates.

FIGURE 9: DRIVERS OF HIGHER CC 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The temporary 100% bonus depreciation included in the 2022/23 CONE value decreases to 20% by 2026, increasing CONE by $25/MW-Day (ICAP).[35] The ATWACC decreased from 8.2% in the prior CONE value to 8.0% currently, decreasing CONE by $4/MW-Day (ICAP), for a net effect of $21/MW-Day (ICAP).
- Cost Escalation: Since the development of the 2022/23 CONE value in our 2018 Study (based on overnight costs of a plant built in 2017), the costs of materials, equipment, and labor costs have escalated along with generalized inflation at a faster rate than expected. For example, from December 2017 to December 2021, material costs increased by 36% compared to

[35] 115th United State Congress, "Tax Cuts and Jobs Act," Signed into law December 22, 2017

expectations of only 10%.[36] With that unexpected escalation over that time period, plus projected escalation to a 2026 installation, total cost escalation to 2026/27 adds $92/MW-Day (ICAP) to the 2x1 CC 2022/23 CONE value.

- Plant Design Updates: The use of dry-cooling ACCs, firm gas transportation contracts (and to a small degree the switch from a 2x2 CC to a double-train 1x1 CCs) as discussed in Section III.A above, adds $66/MW-Day (ICAP) to the 2x1 CC Updated 2026/27 (Estimated) CONE.

III.G. Annual CONE Updates

The PJM tariff specifies that prior to each auction PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review. The updates will account for changes in plant capital costs based on a composite of Department of Commerce's Bureau of Labor Statistic indices for labor, turbines, and materials.

We recommend that PJM continue to update the CONE value prior to each auction using this approach with slight adjustments to the index weightings based on the updated capital cost estimates. As shown in Table 18 below, we recommend that PJM re-weight the components to account for the increasing portion of total plant costs that are from the costs of labor. For the CC, PJM should calculate the composite index based on 40% labor, 45% materials, and 15% turbine. For the CT, PJM should calculate the composite index based on 30% labor, 45% materials, and 25% turbine.

TABLE 18: CONE ANNUAL UPDATE COMPOSITE INDEX

	Combustion Turbine			Combined Cycle		
Component	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index
Labor	20%	30%	30%	25%	43%	40%
Materials	50%	45%	45%	60%	45%	45%
Turbine	30%	25%	25%	15%	12%	15%

PJM will need to account for bonus depreciation declining from 20% for the 2026/2027 BRA to 0% in the 2027/2028 BRA and subsequent auctions. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 1.7% and the CC CONE by 2.1% due to the decreasing depreciation tax shield. We recommend just for the 2027/2028 BRA that after PJM

[36] Material and turbine costs increases are based on BLS Producer Price Index for *Construction Materials* and *Components for Construction* and *Turbines and Turbine Generator Sets* between December 2017 and December 2021. Values may not add to 100% due to rounding.

has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of no longer receiving bonus depreciation by applying an additional gross up of 1.017 for CT and 1.021 for CCs. For subsequent auctions, no further gross up will be necessary.

III.H. E&AS Offset Methodology

The VRR Curve prices are indexed to Net CONE, which is derived by subtracting the reference resource's net energy and ancillary service (E&AS) revenues from its Gross CONE. This E&AS offset could be estimated in a variety of ways. PJM originally estimated it based on actual historical electricity and natural gas prices over the past 3 years. In 2020, PJM adopted a forward-looking approach to calculating the E&AS offset based on forward prices for electricity and natural gas, with hourly shapes based on historical data. FERC subsequently ordered PJM in December 2021 to revert back to the historical method because the forward methodology had been implemented along with PJM's proposed Reserve Pricing Reforms that FERC eventually rejected.

We continue to recommend calculating E&AS on a forward basis over a historical approach. As discussed in our prior reviews, the forward E&AS offset is superior because it reflects expected market conditions that developers will face upon entry into the market. The methodology we helped PJM develop is analytically rigorous, based on forward market data for electricity and natural gas. It is similar to approaches we have implemented for clients and have seen other investors use to estimate their future net E&AS revenues (and, by extension, to estimate how much they would need to earn from the capacity market to enter). By contrast, the backward looking approach reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract (with a willingness-to-pay indexed to estimated Net CONE). Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather conditions that substantially distort the calculation and make it unduly volatile.[37]

However, both historical and forward methods rely on market prices that recently have reflected installed capacity well above the reserve requirement, which can perpetuate disequilibria. When supply is scarce, for example, the E&AS offset will increase and scale down the VRR curve thus

[37] For the same reasons, we recommend forward E&AS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, even if this is not implemented, we still recommend using a forward E&AS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected E&AS revenues.

buy less capacity just when it is needed. This could be avoided by adjusting the E&AS offset to what they would be at the target reserve margin, as NYISO and ISO-NE attempt to do. However, the need for an adjustment is not necessarily clear, without knowing what beliefs about reserve margins underlie forward market prices. Any equilibrium E&AS offset would rely on market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices.

Assuming PJM pursues a forward approach again, we reviewed several aspects of its approach and provide the following recommendation:

- Electric Hub Mapping: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices;
- Natural Gas Hub Mapping: Switch EKPC gas hub from Columbia-App TCO to MichCon; otherwise current gas hub mapping supported by recent prices;
- Ancillary Service Prices: Remove regulation revenues from the calculation of the E&AS offset and scale historical hourly sync and non-sync reserve prices by forward energy prices.

Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate.

PJM also requested that we review the approach for calculating the energy efficiency wholesale energy savings to determine whether the utility EE programs included in the analysis continue to be reasonable. Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts. The current sample includes the largest utilities in each state that provides sufficient detail for the analysis. Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample.

III.I. Implications for Net CONE

III.I.1. Indicative E&AS Offsets

The application of the E&AS offset methodology in Section III.H results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, removal of regulation revenue, and updates to other operating characteristics associated with the technical specifications for the CC.[38] Table 19 shows the effect of each of these changes on the forward-looking 2023/24 E&AS revenue offset by zone for the CC based on simulations provided by PJM staff.

[38] Other parameter updates include updated operating characteristics associated with the most recent turbine models, the addition of dry-cooling, and the 1x1 single shaft CC configuration.

TABLE 19: UPDATED 2023/24 CC E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	CC			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$168	$2	-$24	$146
DPL	$216	$3	-$23	$196
JCPL	$166	$2	-$24	$143
PECO	$184	$14	-$23	$174
PSEG	$162	$2	-$24	$140
RECO	$172	$2	-$23	$151
CONE Area 2				
BGE	$254	$4	-$20	$239
PEPCO	$197	$10	-$21	$185
CONE Area 4				
METED	$212	$15	-$22	$205
PENELEC	$320	$7	-$17	$310
PPL	$190	$15	-$22	$182
CONE Area 3				
AEP	$242	$8	-$21	$229
APS	$281	$5	-$19	$267
ATSI	$208	$44	-$21	$231
COMED	$179	$11	-$22	$168
DAY	$223	$45	-$21	$247
DEOK	$214	$43	-$21	$237
DUQ	$225	$15	-$20	$219
DOM	$195	$9	-$21	$183
EKPC	$246	$14	-$21	$239
RTO	**$189**	**$11**	**-$23**	**$177**

Note: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020. The "Updated 2023/24 EAS" values do not reflect changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

III.I.2. Indicative Net CONE

Net CONE is the estimated annualized fixed costs of new entry, or Gross CONE, of the reference resource, net of estimated E&AS margins and expected performance bonus. PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE. We present in Table 20 below indicative CC Net CONE estimates for all LDAs relative to the parameters used in the 2022/23 MOPR (adjusted here to differentiate CONE values by area).

We say "indicative" because the scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach, but does not include estimating the E&AS offsets for the 2026/27 BRA.

TABLE 20: INDICATIVE CC NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	CC 2022/23 MOPR			CC 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$335	$167	$163	$517	$174	$343
DPL	$335	$208	$122	$517	$231	$286
JCPL	$335	$165	$165	$517	$172	$346
PECO	$335	$186	$144	$517	$206	$311
PSEG	$335	$161	$169	$517	$168	$349
RECO	$335	$171	$159	$517	$180	$337
EMAAC	**$335**	**$181**	**$154**	**$517**	**$189**	**$329**
CONE Area 2						
BGE	$345	$254	$76	$506	$279	$227
PEPCO	$345	$191	$139	$506	$219	$287
SWMAAC	**$345**	**$238**	**$107**	**$506**	**$249**	**$257**
CONE Area 4						
METED	$323	$207	$123	$522	$241	$281
PENELEC	$323	$306	$24	$522	$359	$163
PPL	$323	$185	$145	$522	$216	$307
MAAC	**$334**	**$204**	**$130**	**$517**	**$222**	**$294**
CONE Area 3						
AEP	$316	$233	$97	$518	$268	$251
APS	$316	$272	$58	$518	$311	$208
ATSI	$316	$224	$106	$518	$271	$248
COMED	$316	$195	$135	$518	$199	$319
DAY	$316	$235	$95	$518	$288	$230
DEOK	$316	$224	$106	$518	$277	$242
DUQ	$316	$223	$107	$518	$257	$261
DOM	$316	$181	$149	$518	$216	$303
EKPC	$316	$232	$98	$518	$279	$239
OVEC	$316	$260	$70	$518	$303	$216
RTO	**$330**	**$185**	**$146**	**$516**	**$209**	**$307**

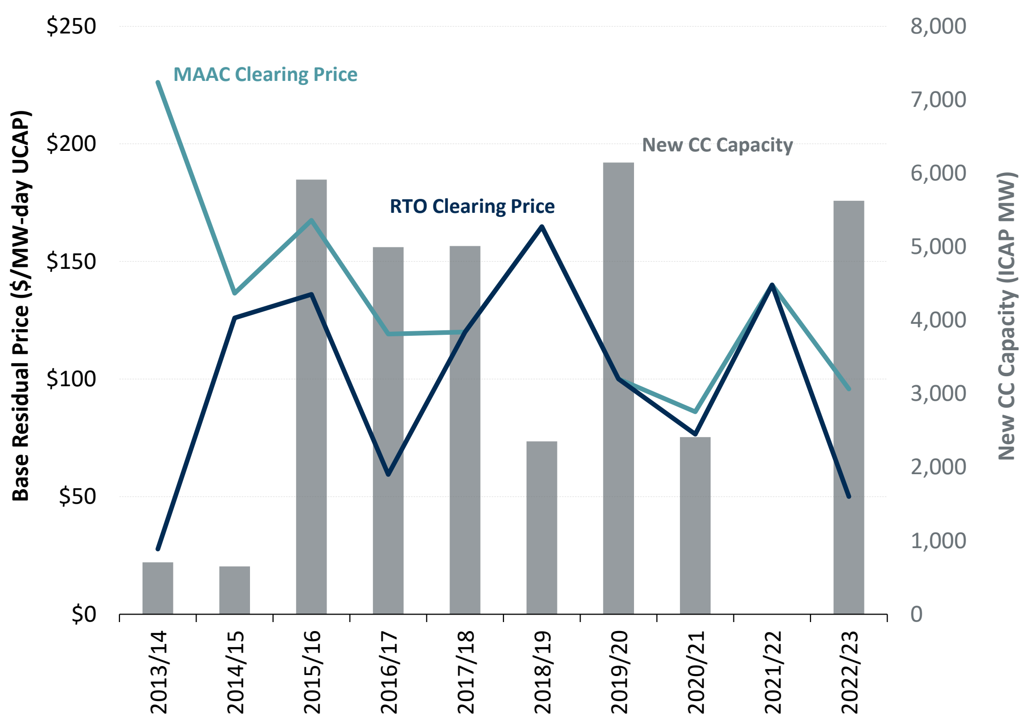
Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

Net CONE is $257–$329/MW-Day (UCAP) across all parent LDAs. Compared to the 2022/23 BRA, the Net CONE roughly doubled for all parent LDAs. Increases in Net CONE are due to the increases in Gross CONE described in Section III.F (cost escalation, decreases in bonus depreciation, and plant design changes) with a slight offset from higher E&AS values. The differences among modeled LDAs and the RTO are similar to the prior.

III.I.3. Comparison to "Empirical Net CONE"

Another informative comparison is to the prices at which actual CCs have been willing to enter the market in past capacity auctions (sometimes referred to as "empirical Net CONE"). Those prices ranged from $75 to $165/MW-Day UCAP in most of the recent auctions, as shown in Figure 10 below. Note that 2022/23 prices should be disregarded as an indicator of willingness to enter since the compressed forward period for that auction meant that new entrants' decisions were already made by the time the auction occurred.

FIGURE 10: HISTORICAL BRA CAPACITY PRICES AND NEW CC CAPACITY



Sources and notes: PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2013/14-2022/23. Please note that the 2022/23 BRA was a compressed auction.

Empirical Net CONE is not a perfect indicator of "true Net CONE" at which capacity could enter at scale—even at the time that capacity entered—because of variability across locations, limited entry in any single auction, and observing only a single clearing price. Some entrants would have entered at prices below the clearing price, whereas uncleared projects, which might have been needed if more retirements or load growth had occurred, would require a higher price. Some may be willing to enter the market at low prices because of their idiosyncratic advantages that cannot be replicated at scale. For example, some past entrants may have enjoyed special opportunities to access natural gas at anomalously low costs earlier in the development of the

Marcellus Shale and export pipelines. Despite these limitations, empirical Net CONE is still a useful benchmark.

Extrapolating backward-looking empirical Net CONE to the future, however, must consider how costs and market conditions have changed. As discussed above, the true cost of entry is in fact increasing due to cost escalation, changes in environmental regulations and plant configurations, and tax laws—by $180/MW-day in our estimation compared to a few years ago. In addition, since the long-term prospects for cash flows have diminished with the industry's transition toward clean energy, entrants may need to front-load their revenues more so than in the past. For example, if they used to assume a 30-year economic life but now assume 20 years, that would further increase Net CONE by $44/MW-day ICAP. Altogether, adding that $180 + $44 to historical empirical Net CONE of $100-165/MW-day, suggests an adjusted benchmark for 2026 of as much as $324-389/MW-day, or $280-345 MW-day without the adjustment for economic life. This is not far from our estimated Net CONE of $257-$329/MW-day across modeled LDAs.

III.I.4. Uncertainty Analysis

There is considerable uncertainty in estimating Net CONE. Most of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, or more if technologies are more constrained by environmental regulations. These examples indicate an uncertainty range on Net CONE of -29% to +16%; the full uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we recommend testing robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

IV. Natural Gas-Fired Combustion Turbines

IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 60HZ
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	361 / 363 / 353 / 350*
Net Heat Rate (HHV in Btu/kWh)	9320 / 9317 / 9304 / 9311*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011

Turbine Model	**Turbine Class**	**PJM**		**US**	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric LM6000	Aeroderivative	7	331	69	3,101
General Electric 7FA	Frame	2	330	14	2,462
Pratt & Whitney FT4000	Aeroderivative	2	120	2	120
Rolls Royce Corp Trent 60	Aeroderivative	2	119	2	119
Pratt & Whitney FT8	Aeroderivative	1	57	4	189
Siemens Unknown	N.A.	1	28	2	545
General Electric LMS100	Aeroderivative	0	0	47	4,664
Siemens SGT6-5000F	Frame	0	0	10	1,892
Rolls Royce Corp Unknown	N.A.	0	0	10	599
General Electric 7EA	Small Frame	0	0	7	417
Siemens AG SGT	Frame	0	0	7	401
General Electric 7HA	Frame	0	0	1	330
All Other Turbine Models		0	0	14	1,297
Total		**15**	**985**	**189**	**16,136**

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that the Perryman Unit 6 CT plant built in 2015 in Maryland included in its operating permit to avoid exceeding emissions thresholds.[39]

- Land: Similar to the reference CC, we estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 10 acres of land are for the reference CT.

TABLE 23: COST OF LAND PURCHASED FOR REFERENCE CT

CONE Area	Land Price *($/acre)*	Plot Size Gas CT *(acres)*	Cost Gas CT *($m)*
1 EMAAC	$36,600	10	$0.37
2 SWMAAC	$29,500	10	$0.30
3 Rest of RTO	$16,400	10	$0.16
4 WMAAC	$30,600	10	$0.31

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

Based on the technical specifications for the CT described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 24 below.

[39] The Perryman Unit 6 operating permit is available here: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Test/Constellation%20Perryman%20Renewal%20Title%20V%202018.pdf

TABLE 24: PLANT CAPITAL COSTS FOR CT REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*361 MW*	*363 MW*	*353 MW*	*350 MW*
Owner Furnished Equipment				
Gas Turbines	$78.6	$78.6	$78.6	$78.6
HRSG / SCR	$33.5	$33.5	$33.5	$33.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$112.1**	**$112.1**	**$112.1**	**$112.1**
EPC Costs				
Equipment				
Other Equipment	$24.1	$24.1	$24.1	$24.1
Construction Labor	$50.6	$37.8	$40.6	$45.0
Other Labor	$16.4	$15.4	$15.6	$16.0
Materials	$8.1	$8.1	$8.1	$8.1
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$21.1	$19.8	$20.1	$20.5
EPC Contingency	$23.2	$21.7	$22.1	$22.6
Total EPC Costs	**$143.6**	**$127.0**	**$130.6**	**$136.3**
Non-EPC Costs				
Project Development	$12.8	$12.0	$12.1	$12.4
Mobilization and Start-Up	$2.6	$2.4	$2.4	$2.5
Net Start-Up Fuel Costs	-$0.6	-$0.6	$0.1	-$0.5
Electrical Interconnection	$7.8	$7.8	$7.6	$7.6
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$0.4	$0.3	$0.2	$0.3
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$1.3	$1.2	$1.2	$1.2
Owner's Contingency	$4.6	$4.6	$4.6	$4.6
Emission Reduction Credit	$0.0	$0.0	$0.0	$0.0
Financing Fees	$7.0	$6.6	$6.7	$6.8
Total Non-EPC Costs	**$69.6**	**$68.0**	**$68.7**	**$68.6**
Total Capital Costs	**$325.3**	**$307.1**	**$311.4**	**$317.0**
Overnight Capital Costs ($million)	**$325**	**$307**	**$311**	**$317**
Overnight Capital Costs ($/kW)	**$902**	**$846**	**$882**	**$906**
Installed Cost ($/kW)	**$945**	**$887**	**$925**	**$949**

IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

TABLE 25: O&M COSTS FOR CT REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *361 MW*	CONE Area 2 SWMAAC *363 MW*	CONE Area 3 Rest of RTO *353 MW*	CONE Area 4 WMAAC *350 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.3	$0.3	$0.3	$0.3
Labor	$1.2	$1.2	$0.9	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.3	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$2.2	$0.3
Insurance	$2.0	$1.8	$1.9	$1.9
Firm Gas Contract	$4.4	$5.4	$7.1	$6.3
Working Capital	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2026$ million)	**$9.5**	**$14.4**	**$13.5**	**$10.9**
Levelized Fixed O&M (2026$/MW-yr)	**$26,300**	**$39,600**	**$38,300**	**$31,300**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	1.19	1.18	1.15	1.22
Total Variable O&M (2026$/MWh)	**1.19**	**1.18**	**1.15**	**1.22**
Major Maintenance - Starts Based ($/factored start, per turbine)	**21,170**	**21,170**	**21,170**	**21,170**

IV.D.CONE Results and Comparisons

Table 26 shows plant capital costs, annual fixed costs, and levelized CONE estimates for the CT reference plant for the 2026/27 delivery year. CONE estimates range from $378/MW-day in EMAAC to $403/MW-day in the Rest of RTO. Note that we assumed accelerated tax depreciation based on the 15-year MACRS for the CT to the depreciable costs after accounting for bonus depreciation.

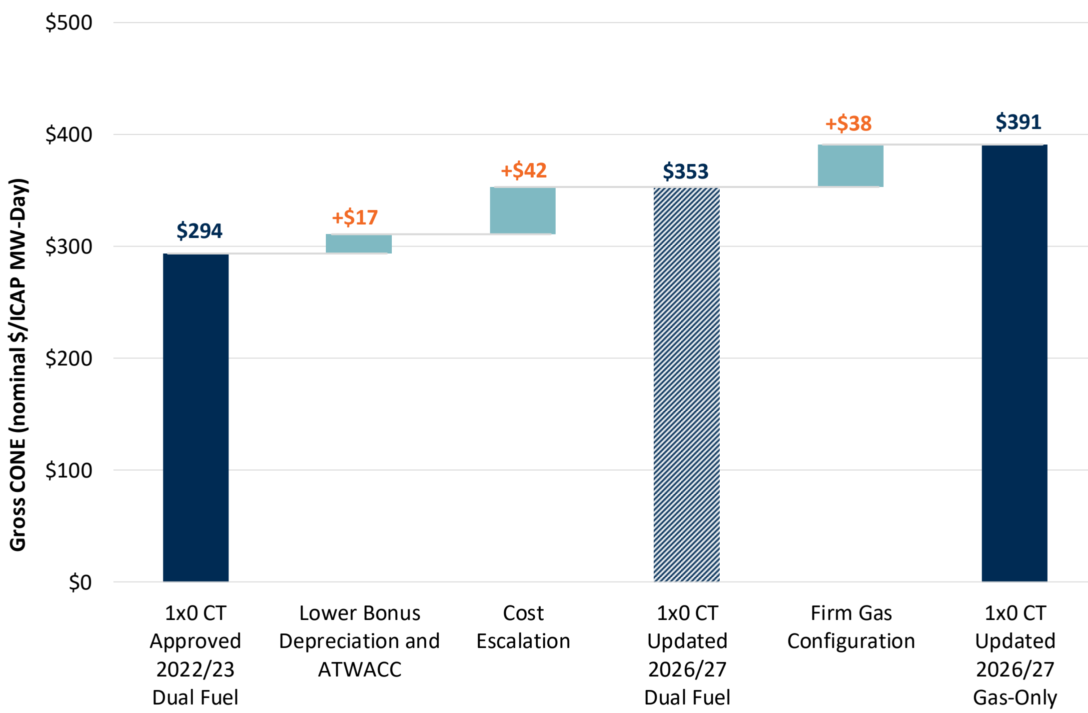
TABLE 26: ESTIMATED CONE FOR CT PLANTS FOR 2026/27 IN 2026$ AND ICAP MW

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$325	$307	$311	$317
[2]	Installed (inc. IDC)	*$m*		$341	$322	$326	$332
[3]	First Year FOM	*$m/yr*		$9	$14	$14	$11
[4]	**Net Summer ICAP**	***MW***		**361**	**363**	**353**	**350**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$902	$846	$882	$906
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$945	$887	$925	$949
[7]	Levelized FOM	*$/kW-yr*		$33	$44	$45	$39
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		11.7%	11.6%	11.6%	11.6%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$138,000**	**$141,700**	**$147,100**	**$144,000**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$378**	**$388**	**$403**	**$395**

Similar to the CC, the CT CONE estimates vary by CONE Area primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

The 2026/27 CT CONE estimates are considerably higher than in PJM's Base Residual Auction for the 2022/23 Delivery Year as shown in Figure 11. Similar to the presentation of CC CONE drivers, the attribution of changes to each element depends on the order in which the changes are implemented in our model. We estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, firm gas configuration.

FIGURE 11: DRIVERS OF HIGHER CT 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The decline to 20% bonus depreciation by 2026 increases CONE by $21/MW-day (ICAP). The ATWACC decreased to 8.0%, decreasing CONE by $4/MW-day (ICAP), for a net effect of $17/MW-Day (ICAP).
- Cost Escalation: Cost escalation is lower relative to the CC due to a lower portion of materials and labor costs associated with the CT. As a result, the total cost escalation to 2026/27 adds $42/MW-Day (ICAP) to the 1x0 CT 2022/23 Dual Fuel CONE value.
- Firm Gas Configuration: The use of firm gas transportation contracts, adds $38/MW-Day (ICAP) to the 1x0 CT Updated Dual Fuel 2026/27 CONE.

IV.E. Implications for Net CONE

IV.E.1. Indicative E&AS Offsets

The E&AS offset methodology described for CCs would also apply to CTs, but recognizing two differences related to CTs' operation as peaking plants that are generally committed day-of. As peaking plants, their dispatch depends more on the hourly volatility of prices that cannot be observed directly in forward markets and are instead taken from historical hourly price shapes. Since historical prices do not fully reflect future conditions, the E&AS offset estimates for CTs may be subject to more uncertainty than for CCs (at least on a percentage basis). This observation does not lead to an obvious recommendation for improving the E&AS offset methodology for CTs but does contribute to our assessment of uncertainty in selecting a suitable reference resource, as discussed above.

The fact that CTs are generally committed day-of does require a slight adjustment to fuel cost inputs in the E&AS offset calculation. As we noted in our 2018 Study, "PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM's Operating Agreement to the variable operating costs of the CTs in the simulations."[41] This time, we are not recommending a "10% adder" that FERC has recently rejected but, more precisely a 10% increase over (day-ahead) gas daily index prices (and no adder on CT VOM costs). This should provide reasonable and necessary adjustment to get more accurate fuel cost inputs.

The application of the CT E&AS offset methodology discussed above results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, then removal of regulation revenue. Table 27 shows the 2023/24 E&AS revenue offset by zone using the updated methodology.

[41] 2018 VRR Curve Study, pp. 23-24.

TABLE 27: UPDATED 2023/24 CT E&AS REVENUE OFFSET BY ZONE

All values in nominal $/MW-day ICAP	CT			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$45	-$4	-$8	$33
DPL	$76	-$2	-$8	$65
JCPL	$43	-$4	-$8	$32
PECO	$48	$4	-$7	$45
PSEG	$41	-$4	-$8	$30
RECO	$48	-$3	-$8	$36
CONE Area 2				
BGE	$93	$6	-$9	$89
PEPCO	$57	-$1	-$7	$49
CONE Area 4				
METED	$65	$8	-$8	$65
PENELEC	$150	$28	-$12	$166
PPL	$52	$5	-$7	$49
CONE Area 3				
AEP	$83	$9	-$12	$79
APS	$114	$17	-$13	$118
ATSI	$66	$16	-$8	$75
COMED	$47	-$6	-$7	$34
DAY	$70	$21	-$8	$83
DEOK	$74	$17	-$8	$83
DUQ	$81	$15	-$8	$89
DOM	$56	-$1	-$7	$48
EKPC	$80	$11	-$10	$81
RTO	**$48**	**-$1**	**-$8**	**$39**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020, including a 10% adder on all variable costs. The "Updated 2023/24 EAS" values do not reflect recommended changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

IV.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the Net CONE shown for the reference CC. Table 28 shows the indicative CT Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 28: INDICATIVE 2026/27 CT NET CONE

All values in nominal $/MW-day UCAP	CT 2022/23 BRA CONE	CT 2022/23 BRA EAS	CT 2022/23 BRA Net CONE	CT 2026/27 Brattle Estimate CONE	CT 2026/27 Brattle Estimate EAS	CT 2026/27 Brattle Estimate Net CONE
CONE Area 1						
AECO	$312	$47	$265	$397	$48	$349
DPL	$312	$76	$236	$397	$85	$312
JCPL	$312	$45	$267	$397	$47	$351
PECO	$312	$54	$258	$397	$62	$336
PSEG	$312	$43	$268	$397	$44	$353
RECO	$312	$50	$262	$397	$52	$346
EMAAC	**$312**	**$52**	**$259**	**$397**	**$56**	**$341**
CONE Area 2						
BGE	$317	$90	$226	$408	$113	$315
PEPCO	$317	$57	$260	$408	$67	$315
SWMAAC	**$317**	**$74**	**$243**	**$408**	**$93**	**$315**
CONE Area 4						
METED	$305	$67	$238	$415	$85	$315
PENELEC	$305	$139	$166	$415	$200	$210
PPL	$305	$54	$250	$415	$67	$315
MAAC	**$311**	**$66**	**$245**	**$404**	**$79**	**$320**
CONE Area 3						
AEP	$305	$77	$227	$424	$101	$315
APS	$305	$102	$203	$424	$146	$315
ATSI	$305	$74	$230	$424	$96	$315
COMED	$305	$57	$248	$424	$49	$421
DAY	$305	$78	$226	$424	$105	$315
DEOK	$305	$81	$224	$424	$106	$315
DUQ	$305	$80	$224	$424	$112	$315
DOM	$305	$54	$250	$424	$65	$315
EKPC	$305	$76	$229	$424	$103	$315
OVEC	$305	$89	$216	$424	$130	$315
RTO	**$309**	**$49**	**$260**	**$411**	**$55**	**$356**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

V. Battery Energy Storage Systems (BESS)

During the stakeholder process, several stakeholders raised concerns about whether natural-gas-fired resources (either CCs or CTs) will be feasible to build in certain zones due to state policies that require a decreasing portion of the generation mix to come from GHG-emitting resources. Based on this input, we reviewed several non-emitting resources to include as possible reference resources and determined that the 4-hour BESS best meets the reference resource screening criteria described in Section II above.

While 4-hour BESS is currently not recommended as the reference resource in any zone, its CONE value provides an initial estimate for PJM and its stakeholders a starting point for future reviews or before then if the recommended reference resource, the gas-fired CC, is determined to be infeasible to be built within the Quadrennial Review period.

V.A. Technical Specifications

We developed the cost estimates for the 4-hour BESS based on the specifications listed in Table 29 below. We assumed the facility is sized for 200 MW at the point of interconnection, based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

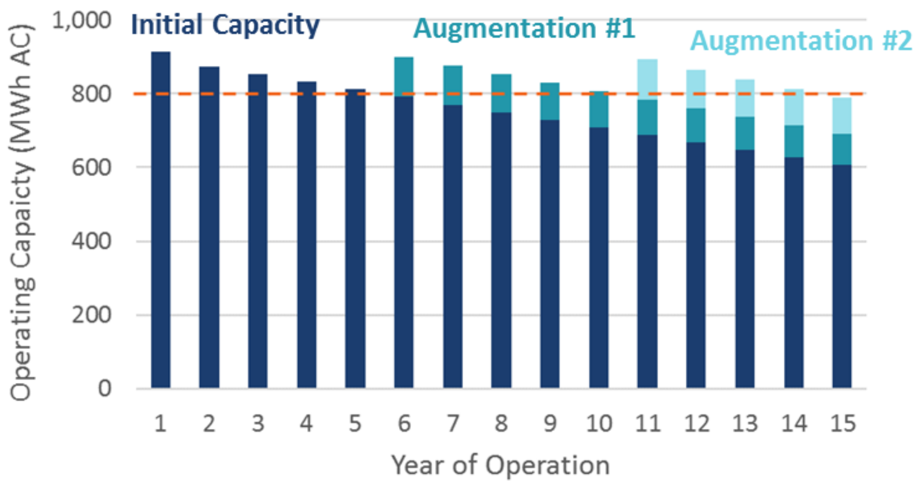
TABLE 29: BESS TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Chemistry	Lithium-ion
Installation Configuration	Containerized
Rated Output Power (at POI)	200 MW-ac
Duration	4 Hours
Installed Energy Capacity	1,030 MWh-dc
Annual Capacity Degradation	4% in Year 1, then 2% per year
Augmentations	Year 5 and Year 10
Use Case	Daily Cycling
Round Trip Efficiency	85%
Economic Life	15 Years
Salvage Value	$0

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4% in the first year and 2% in subsequent years, assuming daily cycling and a 5% minimum state of charge.[42] Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations that reduces the initial capital costs of the facility and may allow the owner to take advantage of declining module costs, depending on future cost trends. To account for degradation of the energy capacity, our cost estimate assumes that the facility will include an initial 13% overbuild, or 135 MWh-dc, with augmentations planned for Year 5 and Year 10. This is currently a common approach developers are taking, based on S&L's recent project experience, to reduce mobilization costs of frequent augmentation while still taking advantage of future costs declines.

42 Degradation occurs due to many factors, including time, ambient conditions, state-of-charge, operational profiles, depth of discharge and manufacturing defects.

FIGURE 12: BESS EENRGY CAPCITY OVER 15 YEAR LIFE



Accounting for the assumed overbuild, minimum state of charge, and on-site losses, the total installed energy capacity is 1,030 MWh-dc, accounting for AC and inverter losses of 6.2%.[43]

TABLE 30: BESS SIZING ASSUMPTIONS

Component	Value
Rated AC Output Power (at POI)	**200 MW-ac**
AC Losses	4.6%
Inverter Losses	1.6%
Gross DC Power Output	**212 MW-dc**
Minimum State of Charge	5.0%
Duration	4 hours
Gross Energy Capacity	**895 MWh-dc**
Overbuild due to Degradation	13%, or 135 MWh-dc
Installed Energy Capacity	**1,030 MWh-dc**

Note: Gross Energy Capacity represents the required capacity to achieve nameplate rated output power on the first day of operation

[43] AC losses include power control system and generator step-up transformer losses, line losses, and auxiliary load.

V.B. Capital Costs

As explained in more detail below, we estimated the 4-hour BESS CONE value using a top-down cost estimating approach that involves less detailed specification of the resource and its location for developing cost estimates. S&L estimated the EPC costs based on recent project data, establishing unitized costs for project components and scaling to the selected reference technology specifications with adjustments to account for labor rates in each CONE Area. S&L then verified the total installed costs against publicly available cost estimates for similar BESS resources.

We estimated the non-EPC costs using similar assumptions as the CC and CT for the per-kW costs of electrical interconnection and per-acre land costs. The remaining non-EPC costs components are estimated based on a percentage of total EPC with the same assumption as the CC and CT for project development, mobilization and start-up, and financing fees. We assumed a lower Owner's Contingency of 5% of BESS equipment costs instead of 8% for the CC and CT based on the larger share of costs covered by the EPC contract.

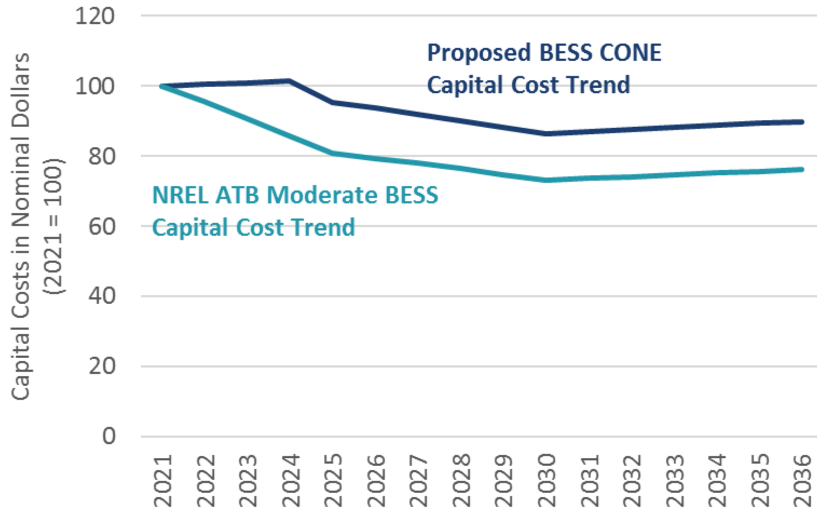
Based on the technical specifications for the reference BESS described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 31 below. EPC costs are primarily driven by the costs of the batteries and enclosures, which is currently estimated to be about $190/kWh-dc (in 2021 dollars). The EPC Contractor Fee and Contingency costs are assumed to be incorporated into the other BESS EPC costs.

TABLE 31: PLANT CAPITAL COSTS FOR BESS REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*200 MW*	*200 MW*	*200 MW*	*200 MW*
EPC Costs				
BESS Equipment				
Batteries and Enclosures	$193.5	$193.5	$193.5	$193.5
PCS and BOP Equipment	$29.0	$29.0	$29.0	$29.0
Project Management	$11.8	$9.4	$10.0	$10.8
Construction & Materials	$58.7	$46.9	$49.6	$53.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	Included	Included	Included	Included
EPC Contingency	Included	Included	Included	Included
Total EPC Costs	**$293.0**	**$278.8**	**$282.0**	**$286.9**
Non-EPC Costs				
Project Development	$14.7	$13.9	$14.1	$14.3
Mobilization and Start-Up	$2.9	$2.8	$2.8	$2.9
Owner's Contingency	$11.1	$11.1	$11.1	$11.1
Electrical Interconnection	$4.1	$4.1	$4.1	$4.1
Land	$0.4	$0.3	$0.2	$0.4
Working Capital	$0.0	$0.0	$0.0	$0.0
Financing Fees	$1.3	$1.3	$1.3	$1.3
Total Non-EPC Costs	**$34.6**	**$33.6**	**$33.6**	**$34.1**
Total Capital Costs	**$327.6**	**$312.4**	**$315.7**	**$321.0**
Overnight Capital Costs ($million)	**$328**	**$312**	**$316**	**$321**
Overnight Capital Costs ($/kW)	**$1,638**	**$1,562**	**$1,578**	**$1,605**
Installed Capital Costs ($/kW)	**$1,725**	**$1,646**	**$1,663**	**$1,691**
Installed Capital Costs ($/kWh)	**$409**	**$390**	**$395**	**$401**

Similar to the CC and CT, all equipment and material costs are initially estimated by S&L in 2021 dollars and escalated to the construction period for an online date of June 1, 2026 based on a 16-month construction drawdown schedule for BESS resources. We estimate the overnight capital cost for the BESS incurred during the construction period, as shown in Figure 13 below. S&L estimates that costs will decline in real terms by -1.5% per year from 2021 to 2024 (or +1.4% per year in nominal terms, given assumed inflation of 2.9% per year), based on contract data, trends, and expectations expressed by suppliers for projects currently in development. From 2024 to 2026, we then assume costs will decline in nominal terms based on the 2021 NREL Annual Technology Baseline Moderate cost projections. We use this approach as well for estimating augmentation costs in 2031 (Year 5) and 2036 (Year 10).

FIGURE 13: PROJECTED BESS CAPITAL COST TRENDS



V.C. Operation and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. Table 9 summarizes the annual fixed O&M costs, variable O&M costs, and augmentation costs in Year 5 and Year 10 for BESS with an online date of June 1, 2026. The annual O&M costs primarily include the fixed costs of the O&M contract for the facility and the costs of operating insurance.

As shown in Figure 12 above, the BESS storage capacity will fall below 800 MWh-ac in Year 6 based on the assumed initial overbuild and degradation rates. To maintain its 4-hour duration at 200 MW of output power through the economic life of the asset, we assume the developer will add 124 MWh-dc of additional battery modules in Year 5 at a cost of $30.5 million (in 2031 dollars) and another 124 MWh-dc of capacity in Year 10 at $33.1 million (in 2036 dollars).[44]

[44] Augmentation costs reflect the current estimate of module of $190/kWh plus a 20% markup for mobilization and installation costs and the projected trend in module costs shown in Figure 13.

TABLE 32: O&M COSTS FOR BESS REFERENCE RESOURCE

O&M Costs	CONE Area			
	1 EMAAC *200 MW*	2 SWMAAC *200 MW*	3 Rest of RTO *200 MW*	4 WMAAC *200 MW*
Fixed O&M Components				
O&M Contract Fixed Payments	$2.7	$2.7	$2.7	$2.7
BOP and Substation O&M	$0.1	$0.1	$0.1	$0.1
Station Load / Aux Load	$0.4	$0.3	$0.3	$0.4
Miscellaneous Owner Costs	$0.3	$0.2	$0.3	$0.3
Operating Insurance	$1.3	$1.2	$1.3	$1.3
Land Lease or Property Taxes	$2.3	$4.4	$2.1	$2.0
Fixed O&M (2026$ million)	**$7.1**	**$9.0**	**$6.7**	**$6.7**
Fixed O&M ($/kW-yr)	**$35.3**	**$44.8**	**$33.6**	**$33.7**
Augmentation				
Year 5 Costs (2031$ million)	**$30.5**	**$30.5**	**$30.5**	**$30.5**
Year 10 Costs (2036$ million)	**$33.1**	**$33.1**	**$33.1**	**$33.1**
Levelized Augmentation Costs ($/kW-yr)	**$22.3**	**$22.3**	**$22.3**	**$22.3**
Total Levelized Fixed Costs ($/kW-yr)	**$57.7**	**$67.1**	**$55.9**	**$56.1**

The total levelized fixed O&M costs represent the total contribution of these costs to the CONE value, including both the annual fixed costs ($23/kW-year to $42/kW-year) and the levelized costs of the two capacity augmentations (about $28/kW-year). While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. All O&M and augmentation costs for the BESS are accounted for in Table 32 and the variable O&M costs are assumed to be $0.

V.D. CONE Estimates

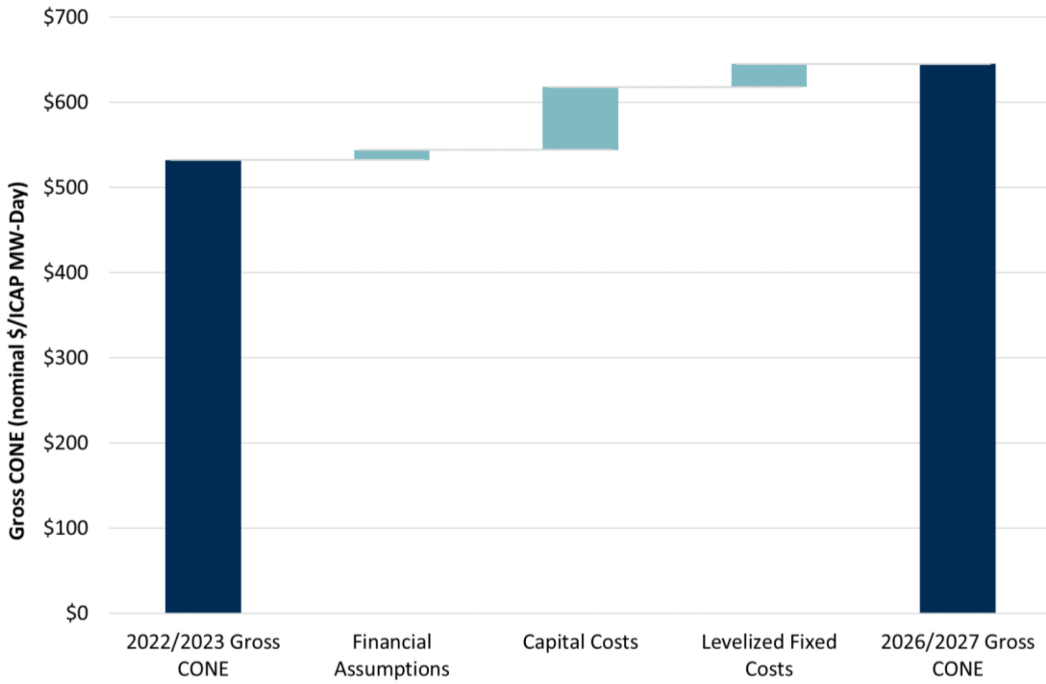
The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 33 summarizes plant capital costs, annual fixed costs, and levelized CONE estimates for the BESS reference resource for the 2026/27 delivery year. The CONE estimates range from $653/MW-day in Rest of RTO to $678/MW-day in EMAAC.

TABLE 33: ESTIMATED CONE FOR BESS FOR 2026/27 IN 2026$ AND ICAP MW

			4-Hour Battery Storage			
			EMAAC	SWMAAC	Rest of RTO	WMAAC
	Net Summer ICAP	*MW*	**200**	**200**	**200**	**200**
	Gross Costs					
[1]	Overnight	*$m*	$328	$312	$316	$321
[2]	Installed (inc. IDC)	*$m*	$345	$329	$333	$338
[3]	First Year FOM	*$m/yr*	$7	$9	$7	$7
[4]	Year 5 Augmentation	*$m*	$31	$31	$31	$31
[5]	Year 10 Augmentation	*$m*	$33	$33	$33	$33
	Unitized Costs					
[7]	Overnight	*$/kW*	$1,638	$1,562	$1,578	$1,605
[8]	Installed (inc. IDC)	*$/kW*	$1,725	$1,646	$1,663	$1,691
[9]	Levelized Fixed Costs	*$/kW-yr*	$66	$69	$64	$64
[10]	**After-Tax WACC**	*%*	**7.9%**	**8.0%**	**8.0%**	**8.0%**
[11]	Effective Charge Rate	*%*	11.1%	11.0%	11.1%	11.1%
[12]	**Updated CONE**	***$/MW-yr***	**$247,400**	**$240,900**	**$238,400**	**$241,500**
[13]	**Updated CONE**	***$/MW-day***	**$678**	**$660**	**$653**	**$662**

Similar to the CC and CT, the 2026/27 BESS CONE estimates are considerably higher than PJM's estimated CONE for the 2022/23 Delivery Year Base Residual Auction, as shown in Figure 14. PJM estimated the 2022/23 CONE based on cost estimates from the NREL Annual Technology Baseline. As described above, the updated estimates for the 2026/27 auction reflect more detailed specifications for a 200 MW facility in the PJM market and recent cost estimates based on actual projects currently under development, including recent cost escalation. As shown in Figure 13 above, the current outlook for BESS capital costs are about 15% higher than those projected by NREL in its latest ATB. The higher capital costs also reflect the assumed overbuild of capacity to account for degradation, whereas NREL assumed no overbuild and annual augmentation. The higher O&M costs reflect the recent costs of maintenance contracts as well as a more up-to-date outlook for future augmentation costs.

FIGURE 14: DRIVERS OF HIGHER BESS 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



V.E. Implications for Net CONE

V.E.1. Indicative E&AS Offsets

Similar to the CC and CT, we recommend removing regulation revenues from the calculation of the E&AS offset for BESS. The regulation market is unlikely to continue to support similar prices in the future with the addition of significant BESS resources, especially in the case in which BESS resource are one of the primary resources that enter the market to meet future reserve requirements.

Removing regulation revenues has a greater impact on BESS E&AS offset than the CC and CT though because it currently makes up the majority of its revenues. Table 34 shows the current and updated 2023/24 E&AS revenue offset by zone with the steep decrease caused by the removal of regulation revenues.

TABLE 34: UPDATED 2023/24 BESS E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	4-Hour BESS Current 2023/24 EAS	4-Hour BESS Removed Regulation	4-Hour BESS Updated 2023/24 EAS
CONE Area 1			
AECO	$414	-$294	$120
DPL	$427	-$285	$142
JCPL	$413	-$295	$118
PECO	$413	-$295	$118
PSEG	$414	-$294	$120
RECO	$419	-$291	$128
CONE Area 2			
BGE	$428	-$267	$161
PEPCO	$423	-$274	$149
CONE Area 4			
METED	$417	-$286	$132
PENELEC	$419	-$290	$128
PPL	$416	-$292	$124
CONE Area 3			
AEP	$418	-$286	$132
APS	$418	-$284	$134
ATSI	$419	-$284	$135
COMED	$425	-$281	$144
DAY	$420	-$281	$139
DEOK	$421	-$280	$141
DUQ	$421	-$283	$139
DOM	$424	-$276	$149
EKPC	$418	-$285	$134
OVEC	$407	-$295	$113
RTO	**$343**	**-$215**	**$128**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020.

V.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the BESS Net CONE shown for the reference CC. Table 28 Table 35 shows the indicative BESS Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 35: INDICATIVE BESS 2026/2027 NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	BESS 2026/27 Brattle Estimate CONE	EAS	Net CONE
CONE Area 1			
AECO	$858	$178	$679
DPL	$858	$208	$649
JCPL	$858	$175	$682
PECO	$858	$175	$683
PSEG	$858	$179	$679
RECO	$858	$189	$668
EMAAC	**$858**	**$184**	**$674**
CONE Area 2			
BGE	$875	$234	$641
PEPCO	$875	$219	$656
SWMAAC	**$875**	**$227**	**$648**
CONE Area 4			
METED	$843	$194	$648
PENELEC	$843	$190	$653
PPL	$843	$184	$659
MAAC	**$857**	**$193**	**$663**
CONE Area 3			
AEP	$830	$195	$635
APS	$830	$198	$632
ATSI	$830	$199	$631
COMED	$830	$211	$619
DAY	$830	$204	$625
DEOK	$830	$208	$622
DUQ	$830	$204	$626
DOM	$830	$218	$612
EKPC	$830	$197	$633
OVEC	$830	$168	$662
RTO	**$851**	**$189**	**$662**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

VI. List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
Btu	British Thermal Units
CAISO	California Independent System Operator
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
DCP	Dominion Cove Point
DJIA	Dow Jones Industrial Average
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kWh	Kilowatt-Hours
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million

MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NO_x	Nitrogen Oxides
NPV	Net Present Value
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VOC	Volatile Organic Compounds
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Combined-Cycle and Combustion Turbine Cost Details

A.1 Technical Specifications

The 2018 PJM CONE study demonstrated that the market was shifting away from the F-class and G-class frame type turbines that had been the dominant turbines over the prior several decades and with over half of the CC plants installed or under construction in PJM. Today, developers even more definitively exhibit preference for H/J-class turbines. Table 36 shows 72% and 58% of CC capacity under construction (since 2018) is from H/J-class turbines in PJM and the U.S., respectively. Among all such turbines, developers continue to select GE 7HA turbine, building on the industry's many turbine-years of operating experience with that make and model. Other equivalent machines to the GE H-class machine such as the Siemens SGT6-8000H or the Mitsubishi M501J currently have lower market penetration.

TABLE 36: TURBINE MODEL OF COMBINED-CYCLE PLANTS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Turbine Model	PJM Installed Capacity *(MW)*	US Installed Capacity *(MW)*
General Electric 7HA	7,211	12,203
Mitsubishi M501J	3,645	3,645
Siemens SGT6-8000H	1,856	1,856
Mitsubishi M501G	1,444	4,015
General Electric 7F	828	4,130
Siemens SGT6-5000F	755	1,426
General Electric A650	717	717
Siemens SGT6-500	703	703
General Electric 6B.03	276	276
General Electric GRT	210	210
General Electric MS7001	0	1,000
Siemens SGT6-2000	0	232
Siemens SGT6-800	0	224
Solar Turbines Titan 130	0	29
Total	**17,645**	**30,666**
F/G Class Total	3,940	10,485
H/J Class Total	12,712	17,704

Sources and notes: Data is from Ventyx Energy Velocity Suite and S&P Global Market Intelligence, Accessed August 2021.

Sargent & Lundy reviewed the operational characteristics of starting up each reference resource and updated the parameters PJM includes in its historical simulations for setting the Net E&AS revenue offset in Table 37.

TABLE 37: RECOMMENDED OPERATING PARAMETERS FOR REFERENCE RESOURCES

Parameter	Unit	CT	CC
Installed Capacity	*MW*	367	1,182
Minimum Stable Level	*MW*	140	176
Ramp Rate	*MW/min*	15	30
Time to Start	*mins*	21	120
Minimum Runtime	*hours*	2	4
NOx Rate	*lb/MMBtu*	0.0093	0.0074
SO2 Rate	*lb/MMBtu*	0.0006	0.0006
Startup Gas Usage	*MMBtu/start*	456	7,988
Startup NOx Emissions	*lb/start*	55	160

A.2 Construction Labor Costs

Labor costs are comprised of "construction labor" associated with the EPC scope of work and "other labor" that includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Labor rates have been developed by S&L through a survey of prevalent wages in each region in 2021. The labor costs for a given task are based on trade rates weighted by the combination of trades required. In areas where multiple labor pools can be drawn upon the trade rates used are the average of the possible labor rates. The labor costs are based on a 5-day 10-hour workweek with per-diem included to attract skilled labor. Site overheads are carried as indirect costs, which is consistent with current industry practice whereas in 2014 site overheads were carried in the labor rates.

A summary of construction labor cost assumptions is shown below in Table 38.

TABLE 38: CONSTRUCTION LABOR COST ASSUMPTIONS

		EMAAC	SWMAAC	Rest of RTO	WMAAC
1x0 CT Plant					
2021 Construction Labor Hours	*hours*	256,453	239,508	243,744	256,453
2021 Weighted Average Crew Rates	*$*	137.66	118.34	122.59	122.44
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$41,657,600	$31,178,500	$33,466,500	$37,051,400
2021 Construction Labor Costs	*$/kW*	115	86	95	106
Double Train 1x1 CC Plant					
2021 Construction Labor Hours	*hours*	1,809,038	1,687,939	1,718,213	1,809,038
2021 Weighted Average Crew Rates	*$*	143.62	127.97	129.48	129.85
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$306,589,500	$237,598,100	$249,164,300	$277,181,900
2021 Construction Labor Costs	*$/kW*	294	227	244	274

Engineering, procurement, and project services are taken as 5% of project direct costs. Construction management and field engineering is taken as 2% of project direct costs. Start-up and commissioning is taken as 1% of project direct costs. These values are consistent with the 2018 CONE Study and are in-line with recent projects in which S&L has been involved.

A.3 Net Startup Fuel Costs

We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume zone-specific gas prices, including Transco Zone 6 Non-New York prices for EMAAC, Transco Zone 5 prices for SWMAAC, Columbia Appalachia prices for Rest of RTO, and Transco Leidy Receipts for WMAAC. All gas prices were calculated by using future/forward natural gas prices from OTC Global Holdings as of 10/10/2021 to estimate 2022 gas prices.
- **Electric Energy:** estimate prices based on zone-specific energy prices for the location of the reference resources in each CONE Area: AECO for EMAAC, PEPCO for SWMAAC, AEP for Rest of RTO, and PPL for WMAAC;[45] average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

[45] Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

TABLE 39: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING

	Energy Production			Fuel Consumption			
	Energy Produced	Energy Price	Energy Sales Credit	Natural Gas	Natural Gas Price	Natural Gas Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT							
1 Eastern MAAC	178,130	$36.24	$6.46	1,636,480	$3.61	$5.9	-$0.6
2 Southwest MAAC	179,290	$36.24	$6.50	1,647,134	$3.61	$5.9	-$0.6
3 Rest of RTO	173,913	$32.45	$5.64	1,598,262	$3.61	$5.8	$0.1
4 Western MAAC	172,584	$36.24	$6.25	1,586,224	$3.61	$5.7	-$0.5
Gas CC							
1 Eastern MAAC	1,027,945	$36.24	$37.26	6,468,335	$3.61	$23.3	-$13.9
2 Southwest MAAC	1,034,170	$36.24	$37.48	6,509,687	$3.61	$23.5	-$14.0
3 Rest of RTO	1,003,905	$32.45	$32.57	6,316,673	$3.61	$22.8	-$9.8
4 Western MAAC	996,320	$36.24	$36.11	6,269,141	$3.61	$22.6	-$13.5

Sources and notes: Energy production and fuel consumption estimated by S&L. Energy prices estimated by Brattle based on approach discussed in Section II.B of VRR curve report. Gas prices from OTC Global Holdings as of 10/10/2021.

A.4 Gas and Electric Interconnection Costs

Similar to the 2018 PJM CONE Study, we identified representative gas pipeline lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project-specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs. We escalated the project-specific costs to 2021 dollars based on the assumed long-term inflation rate of 2.4% (see Table 8 above). We then calculated the average per-mile costs of the laterals ($5.1 million/mile) and the station costs ($4.1 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 40.[46]

[46] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

TABLE 40: GAS INTERCONNECTION COSTS

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(service year $m)*	Pipeline Cost *(2021$m)*	Pipeline Cost *(2021$m/mile)*	Meter Station *(Y/N)*	Station Cost *(service year $m)*	Station Cost *(2021$m)*
Panda Power Lateral Project	TX	2014	16	16.5	$26	$31	$2	Y	$2.2	$2.6
Woodbridge lateral	NJ	2015	20	2.4	$32	$37	$15	Y	$3.5	$4.0
Rock Springs Expansion	PA,MD	2016	20	11.0	$80	$90	$8	Y	$3.3	$3.7
Western Kentucky Lateral Project	KY	2016	24	22.5	$81	$91	$4	Y	$4.8	$5.4
UGI Sunbury Pipeline	PA	2017	20	35.0	$178	$196	$6	Y	n.a.	n.a.
Willis Lateral Project	TX	2020	24	19.0	$96	$98	$5	Y	$4.3	$4.4
Average							**$5.1**			**$4.0**

Sources and notes: A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

Table 41 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CC reference resources. The costs are based on confidential, project-specific cost data provided by PJM for both the direct connection facilities and all necessary network upgrades. In the case where plants chose to build their own direct connection facilities and did not report their costs to PJM, we calculated the capacity-weighted average of the units with direct connection costs and applied them to the units without direct connection costs. We escalated the direct connection and network upgrade costs from the online service dates to 2021 dollars based on the assumed long-term inflation rate of 2.9%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $18.9/kW for setting the electrical interconnection of the CC reference resource.

TABLE 41: ELECTRIC INTERCONNECTION COSTS IN PJM

Plant Size	Observations	Electrical Interconnection Cost Capacity Weighted Average	
	(count)	*(2021$m)*	*(2021$/kW)*
< 500 MW	5	$7.2	$18.3
500-750 MW	5	$12.2	$20.7
> 750 MW	7	$23.9	$18.3
Capacity Weighted Average	**17**	**$18.8**	**$18.9**

Source and notes: Confidential project-specific cost data provided by PJM.

A.5 Land Costs

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We collected all publicly-available land listings for counties within each CONE area. We then calculated the acre-weighted average land price for each CONE area and escalated 1 year using the long-term inflation rate of 2.2%. There is a wide range of prices within the same CONE Area as shown in Table 42.

TABLE 42: CURRENT LAND ASKING PRICES

CONE Area	Current Asking Prices		
	Observations *(count)*	Range *(2022$/acre)*	Land Price *(2022$/acre)*
1 EMAAC	7	$14,430 - $206,620	$96,361
2 SWMAAC	2	$13,148 - $42,785	$29,504
3 RTO	6	$9,867 - $37,429	$16,376
4 WMAAC	6	$22,49 - $68,14	$30,628

Sources and notes: We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

A.6 Property Taxes

Table 43 summarizes the calculations for the effective tax rates of each CONE area. We collected nominal tax rates, assessment ratios, and depreciation rates for counties of each CONE area. Using the nominal tax rates and assessment ratios, the effective tax rate for each CONE area was calculated by multiplying the average nominal tax rate and assessment ratio for counties within each CONE area state.

TABLE 43: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
		(%)	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%/yr)*
1 EMAAC								
New Jersey	[1]	4.0%	96.2%	3.8%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.7%	50.0%	1.3%	3.3%
3 RTO								
Ohio	[3]	5.5%	35.0%	1.9%	5.5%	24.0%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	[4]	2.7%	100.0%	2.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.8%	99.0%	3.8%	n/a	n/a	n/a	n/a

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. For Gloucester County see:
https://tax1.co.monmouth.nj.us/cgi-bin/prc6.cgi?&ms_user=monm&passwd=data&srch_type=0&adv=0&out_type=0&district=0801
For Camden county see:
https://www.camdencounty.com/wp-content/uploads/2020/11/04CAMDEN.2021-Ratios.pdf
https://www.camdencounty.com/wp-content/uploads/2020/11/2021-County-Tax-Rates.pdf

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJ Rev Stat § 54:4-1 (2016).

[2a],[2c] Maryland tax rates estimated based on average county tax rates in Charles county and Prince George's county in 2017-2018. Data obtained from Maryland Department of Assessments & Taxation website:
https://dat.maryland.gov/Documents/statistics/Taxrates_2021.pdf

[2d] MD Tax-Prop Code § 7-237 (2016)

[2e] Phone conversation with representative at Charles County Treasury Department.

[3a],[3c] Ohio rates estimated based on the average effective tax rates from Trumbull and Carroll counties. For Trumbull county see:
http://auditor.co.trumbull.oh.us/pdfs/2020%20RATE%20OF%20TAXATION.pdf
For Caroll County see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202020.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 124 and 129:
http://www.tax.ohio.gov/Portals/0/communications/publications/annual_reports/2016AnnualReport/2016AnnualReport.pdf

[3e] Depreciation schedules for utility assets found in Form U-El by Ohio Department of Taxation:
http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2017/PUE_UEL.xls

[4a] Pennsylvania county tax rates for RTO based on the county of Lawrence, available at:
https://lawrencecountypa.gov/wp-content/uploads/2021/07/2021-millage.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1)* , only real estate tax assessed by local governments.

[5a] Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties:
https://www.luzernecounty.org/DocumentCenter/View/26403/2021-MILLAGES-JULY
https://www.lyco.org/Portals/1/Assessment/Documents/2021%20Millage.pdf?ver=2021-01-29-090920-517
https://bradfordcountypa.org/wp-content/uploads/2021/09/Bradford-County-Mill-Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note assessment ratios above 100% are capped at 100% in our calculations.

[5c]-[5e] According to Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1), only real estate tax assessed by local governments.

AUTHORS

J. Michael Hagerty brings experience in evaluating the costs and market value of new and existing generation resources across the U.S. and Canada. He has assisted wholesale market operators, including AESO, PJM, and ISO-NE, in analyzing the availability and costs of new entry of new renewable resources and natural gas power plants for developing key parameters in their markets. These projects included working closely with engineering consultants and stakeholders developing reference resource specifications and bottom-up cost estimates, developing enhanced approaches for calculating E&AS revenues projections, and estimating cost of capital for merchant generation plants. These projects have required extensive engagement with the client and stakeholders to develop well-supported parameters to capacity market demand curve and clearly present our analyses to stakeholders. He has also completed several policy-focused analyses of the future costs of renewable energy resources for U.S. state agencies, including Rhode Island, Nebraska, and Connecticut. Recently, he has assisted a major renewable energy developer in analyzing the value of solar resources in several states for developing community solar compensation mechanisms. Mr. Hagerty also has experience in wholesale market design, transmission planning and development, and strategic planning for utility companies.

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Dr. Samuel A. Newell is an economist and engineer with 23 years of experience consulting to the electricity industry. His expertise is in the design and analysis of wholesale electricity markets and in the evaluation of energy/environmental policies and investments, including in systems with large amounts of variable energy resources. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

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Dr. Bin Zhou has over twenty years of consulting experience in consumer goods, energy, financial institutions, pharmaceutical and medical devices, technology, telecommunication, and utilities industries. He specializes in the application of financial economics, management accounting, business organizations, and taxation principles to a variety of consulting and litigation settings.

Dr. Zhou has supported testifying experts and led large engagement teams in many high-profile transfer pricing (Microsoft, Facebook, Coca-Cola, Boston Scientific / Guidant, Eaton, AstraZeneca, and GlaxoSmithKline), bankruptcy (Caesars, U.S. Steel Canada, Nortel, Ambac, and Enron), and securities litigations (MBIA, Parmalat, and Enron). His work has been primarily focused on the economic analysis of transfer pricing disputes involving hard-to-value intangibles, economic substance of complex transactions, solvency analysis and fraudulent conveyance claims, structured finance transactions, financial statement analyses, and damages. His most recent experience also includes economic profit analyses in anti-trust matters, a special litigation committee investigation of a large acquisition in the software industry, two international arbitration cases involving valuation of Korean publicly listed companies, two intellectual property transfers in distressed companies, and cost allocation of mutual fund advisory fees.

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Dr. Travis Carless specializes in low-carbon generation, nuclear power, climate policy analysis, and resource planning.

Prior to joining Brattle, Dr. Carless served as a President's Postdoctoral Fellow at Carnegie Mellon University and a Stanton Nuclear Security Fellow at the RAND Corporation. He received an NSF Graduate Research Fellowship for his research, which focused on assessing the environmental competitiveness of small modular reactors (SMRs) and risk and regulatory considerations for SMR emergency planning zones.

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UNIT POWER AGREEMENT

THIS AGREEMENT dated as of March 31, 1982 by and between INDIANA & MICHIGAN ELECTRIC COMPANY ("IMECO") and AEP GENERATING COMPANY ("AEGCO"),

WITNESSETH:

WHEREAS, IMECO, a subsidiary company of American Electric Power Company, Inc. ("AEP") under the Public Utility Holding Company Act of 1935 (the "1935 Act"), is presently constructing the Rockport Steam Electric Generating Plant at a site along the Ohio River near the Town of Rockport, Indiana, which will consist of two 1,300,000-kilowatt fossil-fired steam electric generating units and associated equipment and facilities (the "Rockport Plant"), the first unit ("Unit No. 1") of which is presently expected to be placed in commercial operation in 1984 and the second unit ("Unit No. 2") of which is presently expected to be placed in commercial operation in 1986; and

WHEREAS, AEGCO proposes to enter into an Owners' Agreement, dated as of March 31, 1982 (the "Owners' Agreement"), with IMECO and Kentucky Power Company ("KEPCO"), another subsidiary company of AEP under the 1935 Act, pursuant to which AEGCO and KEPCO plan to acquire undivided ownership interests, as tenants in common without right of partition, in the Rockport Plant which, upon completion of the construction of Unit No. 1, is thereafter to be operated as a part of the interconnected, integrated electric system comprising the American Electric Power System (the "AEP System"); and

WHEREAS, AEGCO proposes, upon completion of the construction of Unit No. 1 and the completion thereafter of the construction of Unit No. 2, to make available to IMECO, pursuant to this agreement, all of the available power (and the energy associated therewith) to which AEGCO shall from time to time be entitled at the Rockport Plant; and

WHEREAS, IMECO proposes to complete the construction of, the Rockport Plant pursuant to the provisions of the Owners' Agreement, and, upon completion of such construction, to operate the Rockport Plant pursuant to an operating agreement to be entered into by IMECO, AEGCO and KEPCO in accordance with the Owners' Agreement;

NOW, THEREFORE, in consideration of the terms and of the agreements hereinafter set forth, the parties hereto agree with each other as follows:

1.1 IMECO and AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 and Section 2.2 of this agreement, use their respective best efforts to complete and to make effective the arrangements described and specified in Section 1.1 and in Section 1.2 of the Capital Funds Agreement, dated as of March 31, 1982, between AEP and AEGCO.

1.2 AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 of this agreement, make available, or cause to be made available, to IMECO all of the power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, including test power produced during the course of the construction of generating units installed as a part of the Rockport Plant.

1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments are to commence under this Section 1.3 to be fair, and authorized, by the Federal Energy Regulatory Commission ("FERC", such term also including any successor Federal regulatory agency) as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Public Service Commission of Indiana as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

2.1 The performance of the obligations of AEGCO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit AEGCO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by IMECO of the construction of the Rockport Plant, the operation of the Rockport Plant, and for AEGCO to make available to IMECO all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant. AEGCO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

2.2 The performance of the obligations of IMECO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities necessary at the time to permit IMECO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities necessary at the time to permit IMECO to pay to AEGCO in consideration for the right to receive all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant the charges provided for in Section 1.3 of this agreement. IMECO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities. IMECO shall, to the extent permitted by law, be obligated to perform its duties and obligations hereunder, subject to then applicable provisions of this Section 2.2, (a) whether or not AEGCO shall have received all authorizations of governmental regulatory authorities necessary to permit AEGCO to perform its duties and obligations hereunder, (b) whether or not such authorizations, or any such authorization, shall at any time in question be in effect, and (c) so long as AEGCO and IMECO shall continue to be subsidiary companies of AEP (as said term is defined in Section 2(a)(8) of the 1935 Act) or a successor thereto, whether or not, at any time in question, IMECO shall have performed its duties and obligations under this agreement. In the event that either AEGCO or IMECO shall cease to be such a subsidiary company, then and thereafter IMECO shall not be relieved of its obligation to make payments pursuant to Section 1.3 of this agreement by reason of the failure of AEGCO to perform its duties and obligations hereunder occasioned by Act of God, fire, flood, explosion, strike, civil or military authority, insurrection, riot, act of the elements, failure of equipment, or for any other cause beyond the control of AEGCO; provided that, in any such event, AEGCO shall use its best efforts to put itself in a position where it can perform its duties and obligations hereunder as soon as is reasonably practicable.

3. To the extent that it may legally do so, IMECO and AEGCO each hereby irrevocably waives any defense based on the adequacy of a remedy at law which may be asserted as a bar to the remedy of specific performance in any action brought against it for specific performance of this agreement by IMECO, by AEGCO, or by a trustee under any mortgage or other debt instrument which IMECO or AEGCO may, subject to requisite regulatory authority, enter into, or by any receiver or trustee appointed for IMECO or AEGCO under the bankruptcy or insolvency laws of any jurisdiction to which IMECO or AEGCO is or may be subject; provided, however, that nothing herein contained shall be deemed to constitute a representation or warranty by IMECO or AEGCO that the respective obligations of IMECO or AEGCO under this agreement are, as a matter of law, subject to the equitable remedy of specific performance.

4. IMECO shall not be entitled to set off against any payment required to be made by IMECO under this agreement (i) any amounts owed by AEGCO to IMECO or (ii) the amount of any claim by IMECO against AEGCO. The foregoing, however, shall not affect in any other way the rights and remedies of IMECO with respect to any such amounts owed to IMECO by AEGCO or any such claim by IMECO against AEGCO.

5. The invalidity and unenforceability of any provision of this agreement shall not affect the remaining provisions hereof.

6. This agreement shall become effective forthwith and shall continue until all of the Notes issued by AEGCO under the Revolving Credit Agreement, dated as of March 31, 1982, of AEGCO shall have been paid in full, together with all accrued interest thereon; provided, however, that in the event that AEGCO shall, prior to such payment, create a Mortgage and Deed of Trust secured by a lien on all, or certain of its fixed physical properties, and shall issue bonds thereunder, this agreement shall continue until said Mortgage and Deed of Trust shall have been satisfied and discharged or said Notes have been paid in full, whichever event shall be the later.

7. This agreement shall be binding upon the parties hereto and their successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this agreement, shall in any event relieve either IMECO or AEGCO of any of their respective obligations hereunder, or, in the case of IMECO, reduce to any extent its entitlement to receive all of the power (and the energy associated therewith) available to AEGCO from time to time at the Rockport Plant.

8. The agreements herein set forth have been made for the benefit of IMECO and AEGCO and their respective successors and assigns, and no other person shall acquire or have any right under or by virtue of this agreement.

9. IMECO and AEGCO may, subject to the provisions of this agreement, enter into a further agreement or agreements between IMECO and AEGCO setting forth detailed terms and provisions relating to the performance by IMECO and AEGCO of their respective obligations under this agreement. No agreement entered into under this Section 9 shall, however, alter to any substantive degree the obligations of either party to this agreement in any manner inconsistent with any of the foregoing sections of this agreement.

10. IMECO shall, at any time and from time to time, be entitled to assign all of its right, title and interest in and to all of the power (and the energy associated therewith) to which IMECO shall be entitled under this agreement, but IMECO shall not, by such assignment, be relieved of any of its obligations and duties under this agreement except through the payment to AEGCO, by or on behalf of IMECO, of the amount or amounts which IMECO shall be obligated to pay pursuant to the terms of this agreement.

6

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be duly executed as of the day and year first above written.

INDIANA & MICHIGAN ELECTRIC COMPANY

By G. P. Maloney
Vice President

AEP GENERATING COMPANY

By G. P. Maloney
Vice President

Docket No.: ER19-470-000
Company: AEP
FERC El. Rate Sch. No.: 1
Supp. No.: 6
Filing Date: 5-30-19
Effective Date: I 0 5

1.6

AMENDMENT NO. 1

TO UNIT POWER AGREEMENT

This Amendment No. 1 dated as of May 8, 1989 by and between Indiana Michigan Power Company ("I&M" or "IMECO", formerly known as Indiana & Michigan Electric Company) and AEP Generating Company ("AEGCO") to the Unit Power Agreement dated as of March 31, 1982 by and between I&M and AEGCO ("Unit Power Agreement"),

WITNESSETH:

WHEREAS, I&M and AEGCO have entered into the Unit Power Agreement whereby, subject to regulatory approvals and certain other conditions, AEGCO agreed to make available, or cause to be made available, to I&M all of the power (and the energy associated therewith) which is available to AEGCO at the Rockport Plant and I&M agreed to pay AEGCO certain amounts;

WHEREAS, AEGCO has entered into six Participation Agreements, dated as of March 15, 1989, whereby it has agreed, subject to regulatory approvals and certain other conditions, to sell its 50% undivided interest in Unit 2 of the Rockport Plant and pursuant to six separate leases (the "Leases"), to leaseback a 50% undivided interest in the unit; and

WHEREAS, Section 3.01 of the Participation Agreements specify that as a condition to closing AEGCO and I&M shall have entered into, and shall have filed with the Federal Energy Regulatory Commission ("FERC") for its approval, an amendment to the Unit Power Agreement which shall, among other things, (i) specifically confirm that basic rent payable under the Leases is an item of operating and other expenses of AEGCO referred to in Section 1.3 thereof, and (ii) specifically provide that the Unit Power Agreement shall continue in full force and effect until the lease term shall have expired or been terminated and all basic rent payable under the Leases shall have been paid in full;

NOW, THEREFORE, in consideration of the terms and agreements hereinafter set forth, the parties hereto agree as follows:

1. Section 1.3 of the Unit Power Agreement is hereby amended to read as follows:

"1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities, and lease rental payments, including any amount of Basic Rent (as such term is defined in Section 3(a) of the forms of Lease attached as Exhibit A to the Participation Agreements) which AEGCO may be required to pay pursuant to the Leases, and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time, and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments

76

are to commence under this Section 1.3 to be fair, and authorized, by the FERC, including any successor Federal regulatory agency as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Indiana Utility Regulatory Commission as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant."

2. Section 6 of the Unit Power Agreement is hereby amended to read as follows:

"6. This agreement shall become effective forthwith and shall continue in full force and effect until the latter of the date that: (1) all of the Notes issued by AEGCO under the Revolving Credit Agreement, dated as of March 31, 1982, of AEGCO shall have been paid in full, together with all accrued interest thereon; or (ii) the last of the Lease Terms (as that term is defined in the Participation Agreements) shall have expired or been terminated and all Basic Rent payable under all of the Leases shall have been paid in full; provided, however, that in the event that AEGCO shall, prior to such payment, create a Mortgage and Deed of Trust secured by a lien on all, or certain of its fixed physical properties, and shall issue bonds thereunder, this agreement shall continue until said Mortgage and Deed of Trust shall have been satisfied and discharged."

3. This Amendment No. 1 shall become effective on the date on which the last of the following events shall have occurred: (i) this Amendment No. 1 shall have been filed with and accepted for filing without condition or change by the FERC under the Federal Power Act (FPA) as a rate schedule under circumstances where the FERC (a) shall have issued an order under the FPA that

771

this Amendment No. 1 shall become effective in its entirety as such rate schedule under the FPA, as proposed by the parties in their filings with the FERC, and (b) shall not have, in such order or any separate order, instituted an investigation or proceeding under the provisions of the FPA with respect to the justness and reasonableness of the provisions of this Amendment No. 1; (ii) the order or orders of the FERC, referred to in (i) above, shall have become final and not subject to review under Section 313 of the FPA; or (iii) the Closings (as defined in the Participation Agreements).

IN WITNESS WHEREOF, the parties hereto have caused this Amendment No. 1 to be duly executed as of the date and year first above written.

INDIANA MICHIGAN POWER COMPANY

By: /s/ R. E. DISBROW
Vice President

AEP GENERATING COMPANY

By: /s/ G. P. MALONEY
Vice President

RATE DESIGN

The total revenue requirement of AEGCO calculated pursuant to the IMECO-AEGCO Unit Power Agreement designated AEGCO FERC Rate Schedule No. 1 is designed to recover for AEGCO its total cost of providing power (and the energy associated therewith) available to AEGCO at the Rockport Plant.

DETERMINATION OF POWER BILL

In accordance with Section 1.3 of the Unit Power Agreement, I&M agrees to pay AEGCO in consideration for the right to receive all power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M), such amounts, less any amounts recovered by AEGCO from other sources, as shall be determined monthly as described below. Such amounts shall be calculated separately for Unit No. 1 (including Common Facilities) and for Unit No. 2. I&M shall then commence the payment of such amounts (power bill) on the earlier of the following dates: (i) June 30, 1985 and (ii) the date on which power including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

The power bill for Unit No. 1 (including Common Facilities) shall be calculated each month and shall reflect recovery only of those costs related to the plant in service. It shall consist of the sum of (a) a return on common equity, (b) a return on other capital, (c) recovery of operating expenses and (d) provision for federal income taxes as described below and as illustrated in the example attached.

(a) Return on Common Equity, which shall be equal to the product of (i) the amount of common equity outstanding at the end of the previous month, but not more than 40% of the capitalization of AEGCO at the end of the previous month; (ii) 1.0133 (12.16% annual rate) as described in Note 1 below; (iii) the Operating Ratio, as defined in Note 2 below; and (iv) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below, plus the product of (v) the amount of common equity in excess of 40% of the capitalization of AEGCO at the end of the previous month, if any such excess shall be determined; (vi) the weighted cost of debt outstanding at the end of the previous month; (vii) the Operating Ratio, as defined in Note 2 below; and (viii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, the amount of common equity shall be equal to the sum of the Common Stock (Accounts 201-203, 209, 210, 212, 214 and 217), Other Paid-In Capital (Accounts 207, 208, 211 and 213), and Retained Earnings (Accounts 215-216) outstanding at the end of the previous month. Total capitalization shall be equal to the sum of Long-term Debt (Accounts 221-226 including current maturities and unamortized debt premium and discounts), Short-Term Debt (Accounts 231 and 233), Preferred Stock (Accounts 204-206), and Common Equity less any Temporary Cash Investments, Special

Deposits and Working Funds (Accounts 132-134, 136, and 145) outstanding at the end of the previous month.

(b) Return on Other Capital, which shall be equal to the product of (i) the amount equal to the net interest expense associated with Long-Term and Short-Term Debt, net of any Temporary Cash Investments, Special Deposits and Working Funds, plus the preferred stock dividend requirement associated with the Preferred Stock outstanding at the end of the previous month; (ii) the Operating Ratio, as defined in Note 2 below; and (iii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, net interest expense shall be equal to the sum of (i) the amount of Long-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Long-Term Debt and (ii) the amount of Short-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Short-Term Debt, less (iii) the amount of Temporary Cash Investments, Special Deposits and Working Funds outstanding at the end of the previous month multiplied by the weighted cost of Long Term and Short-Term Debt combined determined pursuant to (i) and (ii) above.

(c) Recovery of Operating Expenses, excluding federal income taxes, which shall consist of provision for depreciation and amortization (Accounts 403-407, 411), including Asset Retirement Obligation (ARO) depreciation and accretion expenses (Accounts 403.1 and 411.10), taxes other than federal income taxes (Accounts 408-411) and operating and maintenance expenses associated with Unit No. 1 (including Common Facilities) offset by other operating revenues as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities (See Note 6). Recovery of expenses for test energy shall be limited to recovery of actual fuel expense as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities. Operating and maintenance expenses shall include, and reflect the recovery of, Steam Power Generation Expenses (Accounts 500-515 including lease rental payments recorded in Account 507), Other Power Supply Expenses (Accounts 555-557), Transmission Expenses (Accounts 560-574), Distribution Expenses (Accounts 580-598), Customer Accounts Expenses (Accounts 901-905), Customer Service and Informational Expenses (Accounts 906-910), Sales Expenses (Accounts 911-917) and Administrative and General Expenses (Accounts 920-933 and 935). Recovery of 501 fuel expenses shall be adjusted to reflect the deferral and/or feedback of unrecovered levelized fuel expenses as may be recorded on the Company's books or as is currently recorded on the books of I&M.

(d) Provision for Unit No. 1's (including Common Facilities) allocated share of net current and deferred federal income tax expense and investment tax credit included in operating income as determined by the Company in accordance with federal income tax law, SEC approved consolidated current tax allocation procedures, and FERC rules and regulations.

For purposes of computing federal income taxes, the interest expense deduction shall be equal to the sum of the net interest expense computed in accordance with paragraph (b) above plus the imputed interest expense associated with common equity that is in excess of 40% of AEGCO's net capitalization.

The power bill for Unit No. 2 shall be calculated in the same manner as described for Unit No. 1 above except that it shall reflect the Unit No. 2 Net In-Service Investment Ratio and those expenses associated with Unit No. 2.

Notes:

1. **Return on Equity**

The return on common equity allowance shall be based upon a rate of return of 12.16% as set forth in sub-paragraph (a) above.

In October of 1988, and every October thereafter for the effective duration of AEGCO's formula rate, any purchaser under AEGCO's two unit power agreements, any state regulatory commission having jurisdiction over the retail rates of purchasers under these agreements, or any other entity representing customers' interest, may file a complaint with the Commission with respect to the specified rate of return on common equity. If the Commission, in response to such a complaint, or on its own motion, institutes an investigation into the reasonableness of the specified return on common equity, such investigation shall be pursued under the special procedures set forth as follows:

A. The only issue to be addressed under these special procedures shall be the continued collection of the return on equity as incorporated in the formula rate; and

B. Refund will be due, should the return on equity, specified in the formula be found not just and reasonable, dating from the first day of January immediately following the date the complaint is filed or an investigation is instituted by the Commission on its own motion, calculated on the resulting difference in rates due to the application of the return found to be just and reasonable and the return stated in the formula. The first such effective date for the calculation of refunds shall be January 1, 1989.

Any other complaint which challenges the justness and reasonableness of any other component of the filed formula rate or any other complaint filed at any other time which challenges the justness and reasonableness of the specified rate of return on common equity and which is set for investigation by the Commission shall be pursued under Section 206 of the Federal Power Act.

2. **Operating Ratio**

The Operating Ratio shall be computed each month commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform

System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived by dividing (a) the amount of Electric Plant In Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations); less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111 but excluding amounts associated with Asset Retirement Obligations); plus Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below); Materials and Supplies (Accounts 151-156 and 163 as adjusted pursuant to the provisions of Note 4.C. below); Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below); Prepayments (Account 165); Deferred Ash pond cost (Account 182.3); other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 less Accounts 232-234, 236, 237, 238, 241 and 242); and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No. 2); less Asset Retirement Obligation (Account 230); less Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the plant in service by (b) the sum of (i) the amount determined pursuant to (a) plus (ii) the amount of Construction Work In Progress (Account 707) plus Materials and Supplies (Accounts 151-156 and 163), less Accumulated Deferred Federal Income Taxes related to the construction work in progress plus (iii) Plant Held for Future Use (Account 105), Other Deferred Debits (Account 186) and the amount of fuel inventory over the allowed level (Account 151.10) not otherwise included in (a) above.

3. Net In-Service Investment Ratio

The Unit No. 1 Net In-Service Investment Ratio shall be equal to 1.0 during the period commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation and shall remain at 1.0 up to, but not including, the month in which Unit No. 2 at the Plant is placed in commercial operation. Thereafter, the Net In-Service Investment Ratio shall be computed each month, based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived as follows:

A. Unit No. 1 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 1 and Common Facilities by (b) the sum of the Net In-Service Investment associated with Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

B. Unit No. 2 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 2 by (b) the sum of the Net In-Service Investment associated with the Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

4. **Net In-Service Investment**

The Net In-Service Investment shall be computed each month commencing with the month in which Unit No. 2 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall consist of the following:

A. Unit No. 1 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), and Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 <u>less</u> Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253), less Asset Retirement Obligation (Account 230), less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to such Unit No. 1 and Common Facilities in-service investment.

B. Unit No. 2 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 <u>less</u> Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No.2), less Asset Retirement Obligation (Account 230), less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the Unit No. 2 in-service investment.

C. AEGCO shall be permitted to earn a return on its fuel inventory, recorded in Account 151.10, not in excess of a 68-day coal supply as defined herein. To the extent AEGCO's actual fuel inventory exceeds the allowable 68-day level, the return on such excess shall be recorded in a memo account. When AEGCO's actual fuel inventory is less than the allowable 68-day level, AEGCO shall be permitted to recover the return previously unrecovered, but in no event shall the power bill reflect a return on fuel inventory in excess of 68-day supply.

A 68-day coal inventory level shall be determined for each unit annually, and shall be based upon the actual experienced daily burn during the preceding calendar year. The actual experienced daily burn shall be defined to exclude the effect of forced and scheduled outages as well as curtailments as follows:

For each unit:

$$\text{Actual experienced daily burn} = 24 \text{ hours} \quad \left(\frac{\text{Tons burned per year}}{\text{Operating hours}}\right)$$

Where:

Operating hours = Hours in year minus forced and scheduled outage hours minus curtailment equivalent outage hours

and

Curtailment equivalent outage hours = The product for each curtailment of:

$$\frac{\text{kW of curtailed capacity}}{\text{kW of rated capacity}} \quad \text{x} \quad \text{Curtailment hours}$$

The value of the allowable 68-day coal supply used to determine each month's power bill shall be equal to the number of tons determined above multiplied by the cost per ton of coal in inventory at the end of the previous month.

For 1990, a 68-day coal supply for AEGCO's share of Rockport Unit No. 2 shall be based on 12 months ending December 1990 data. For 1990 billing purposes, however, a 68-day coal supply for AEGCO's share of Rockport Unit No.2 shall initially be assumed to be equal to the 68-day coal supply for AEGCO's share of Rockport Unit No. 1, adjusted to reflect the Btu content and the unit cost of the coal for Rockport Unit No. 2.

AEGCO shall maintain a cumulative record of the unrecovered return as well as the subsequent recovery of that return as follows:

i) To the extent that AEGCO's actual fuel inventory exceeds the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the sum of the unrecovered return on fuel inventory and the return on previously unrecovered amounts. The unrecovered return on fuel inventory shall be calculated each month by deriving the difference between the power bill that would result if full recovery were provided and the power bill that results with the 68-day limitation imposed. The return on previously unrecovered amounts shall be calculated by multiplying the cumulative return unrecovered at the end of the previous month by the capital costs used to derive the power bill, adjusted for federal income taxes.

ii) To the extent that AEGCO's fuel inventory is less than the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the return on previously unrecovered amounts less the recovered return in excess of actual inventory levels. The return on previously unrecovered amounts shall be calculated as described in (i) above. The recovered return in excess of actual inventory levels shall be calculated by deriving the difference between the power bill that would result if actual inventory balances were used and the power bill that results with an imputed inventory level. In no event will the cumulative value of the unrecovered return be allowed to fall below zero.

D. AEGCO shall be permitted to include as part of its Net In-Service Investment Numerator amounts subsequently recorded in Accounts 105 and 186 subject to the conditions set forth in the Offer of Settlement in FERC Docket No. ER84-579-000, et al.

E. Other Special Funds (Account 128), Other Current and Accrued Assets (Accounts 131, 135, 143, 146, 171 and 174), Other Deferred Debits (Account 181), Other Current and Accrued Liabilities (Accounts 232-234, 236, 237, 238, 241 and 242), and Other Deferred Credits (Account 253) shall be directly assigned to unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such balances shall be allocated between the units in proportion to the net dependable capability of each of the units.

F. To recognize that the lease rental expense will be collected monthly but that the lease payment will be paid semiannually, the lease rental payable balance will be reflected as a rate base reduction in calculating the operating ratio and the Unit 2 net-in-service investment ratio as a means to credit the Unit 2 customers for the time value of money.

5. **Investment Balances**

For the purpose of calculating the Operating Ratio and Net In-Service Investment Ratio, amounts shall reflect the balances, as recorded on the Company's book in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month, except that when plant greater than or equal to 1% of the prior month ending plant value is transferred into service during the current month, such prior month balances shall be adjusted to reflect such transfers to service. Such adjustment shall be pro-rated for the number of days during the month that such plant addition was in-service.

6. **Allocation of Expenses**

Operating expenses shall be directly assigned to Unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such expenses shall be allocated between the units in accordance with the basis that gave rise to such expense.

AEGCO's operating and maintenance expenses shall include, and AEGCO shall be allowed recovery of, administrative and general expenses, related payroll taxes and other cost, allocated to AEGCO by I&M as operator of the Rockport Plant or incurred directly by AEGCO.

I&M shall allocate to AEGCO, a portion of I&M's administrative and general expenses charged to Accounts 920, 921, 922, 923, 924, 925, 926, 931 and 935; related payroll taxes charge to Account 408; and a portion of the expenses of the Rockport Information Center charged to Accounts 506, 511 and 514 that generally relate to Rockport Plant operations. Such charges shall be allocated to AEGCO on the basis of the ratio of AEGCO's share of the Rockport Plant operation and maintenance wages and salaries, divided by the sum of total Rockport Plant operations and maintenance wages and salaries, plus all other I&M operation and maintenance wages and salaries, less I&M's administrative and general wages and salaries. For the period beginning December 10, 1984 and ending December 31, 1985 this ratio will be developed based on actual 1985 amounts. In subsequent calendar years, this ratio will be adjusted annually based on the prior calendar year's amounts.

AEGCO's operation and maintenance expenses shall also include, and AEGCO shall be allowed recovery of, other administrative and general expenses directly incurred by AEGCO and included in the appropriate administrative and general expense accounts.

BILLINGS AND PAYMENTS

All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the

Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon, the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of the unit power agreements.

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 2
CASE NO. U-20530 (2020 PSCR RECONCILIATION)

DATA REQUEST NO. 2-29-AG

Request

Refer to AG 1-11 attachment 1:

a. Has the Michigan Public Service Commission ever approved this agreement? If yes, identify the case number and order date.

b. Referring to section 1.3 of the agreement, how was the return on equity calculated?

c. Referring to section 1.3 of the agreement, provide the amounts received by AEG from any other sources in 2020, and explain how those amounts were used to calculate the amount I&M owed.

d. Identify all actions I&M has taken since the Commission's June 7, 2019 Order in Case No. U-18404 to seek or pursue amendments, new contractual arrangements, or other negotiations regarding any aspect of this agreement, including but not limited to the return on equity.

e. Produce all documents and communications related to your response to the preceding sub-part.

Response

a. The Commission originally approved the inclusion of the capacity charges related to the purchase of Rockport Plant Unit 2 capacity from AEP Generating Company (AEG) in its order in Case No. U-9656, dated Feb. 12, 1991. Furthermore, the costs of the Unit Power Agreement with AEG have been included in all subsequent base rate cases and power supply cost recovery cases since that date.

b. The calculation for the return on equity component of the bill is based on the method identified in AEP Generating Company Rate Schedule No. 1, on file with the FERC.

c. I&M objects to this request on the basis that it seeks information that is outside the scope of the PSCR and, therefore, is not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, the Company states that any amounts received by AEG other than those costs included in the Company's 2020 PSCR Reconciliation filing are not relevant in determining the reasonableness of the costs included in this reconciliation proceeding.

d. Please see FERC Docket no. ER19-717-000 for the most recent rate update filing made on behalf of AEP Generating Company to update their formula rate calculation.

e. The docket and all pertinent documents can be found at FERC.gov.

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 2
CASE NO. U-20530 (2020 PSCR RECONCILIATION)

SUPPLEMENTAL RESPONSE

c. I&M objects to the extent this question seeks information that is confidential and proprietary. Without waiving this objection, the confidential information will be provided pursuant to the protective order issued May 24, 2021 in this docket. Please see the following AEG Power Bills:

- AG 2-29 CONFIDENTIAL 01_January_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 02_February_2020_Actual.xls
- AG 2-29 CONFIDENTIAL 03_March_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 04_April_2020_Estimation.xls
- AG 2-29 CONFIDENTIAL 05_May_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 06_June_2020_ESTIMATE.xls
- AG 2-29 CONFIDENTIAL 07_July_2020_ESTIMATE.xls
- AG 2-29 CONFIDENTIAL 08_August_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 09_September_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 10_October_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 11_November_2020_Estimated Version 2.xls
- AG 2-29 CONFIDENTIAL 12_December_2020_Estimation.xls

As to objection
Counsel

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
DATA REQUEST SET NO. AG-SC-CUB SET 1
CASE NO. U-21428

DATA REQUEST NO. AGSCCUB 1-22

Request

Provide the ICAP for AEG in 2024.

Response

I&M objects to this request on the grounds it is vague, ambiguous and confusing and cannot be answered in its current form because it is not clear what “ICAP for AEG” means.

Subject to and without waiving objections, the Company interprets the question as seeking the Installed Capacity (ICAP) value for the Company's share of Rockport Unit 1 obtained through its Unit Power Agreement with AEP Generating Co. (AEG). Furthermore, ICAP values are established by PJM Planning Year which runs from June 1 to May 31. The Company's ICAP value for Rockport Unit 1 was 1317.5 MW for both the 2023-2024 and 2024-2025 PJM Planning Years. The portion obtained through the Unit Power Agreement is 50% of that value.

Preparer:

Jason M. Stegall

PROOF OF SERVICE - U-21428

The undersigned certifies that a copy of the ***Direct Testimony and Exhibits of Devi Glick on behalf of the AG, SC, and CUB*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 17th day of October 2025.

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