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Results and Likely Impacts of PJM's 2025/26 Base Residual Auction

Prepared for:

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Executive Summary

The PJM 2025/26 Base Residual Auction (BRA), released in July 2024, produced results that reverberated across the electricity market, with capacity prices skyrocketing to $269.92 per megawatt-day (MW-d) for the Regional Transmission Organization (RTO) footprint—a nearly tenfold increase from the previous auction. This sharp rise is primarily attributed to significant changes in the market structure, including a higher forecasted peak load, an increased Installed Reserve Margin (IRM), and modifications to the Effective Load Carrying Capability (ELCC) for various resource types. These changes collectively resulted in a dramatic shift in the supply-demand balance, pushing capacity prices to historic highs.

Main Drivers of the Record-Setting Auction Results:

1. **Increased Forecasted Peak Load:** PJM raised its forecasted peak load by 2.2%, driven by the growing electrification of the transportation sector and substantial demand growth from data centers. This adjustment reflected an anticipated rise in electricity demand, particularly in areas like Northern Virginia and Chicago, where data center growth is accelerating.

2. **Higher Installed Reserve Margin (IRM) Target:** The IRM target was increased by 3.1 percentage points to 17.8%, a response to reliability concerns highlighted by past extreme weather events, such as Winter Storm Elliott in December 2022. This adjustment contributed significantly to the overall increase in capacity requirements.

3. **Changes in Capacity Accreditation:** PJM extended ELCC accreditation to all generating resources, resulting in a significant reduction in accredited unforced capacity (UCAP) for natural gas-fired and solar resources. This change alone effectively reduced available capacity by nearly 25,000 MW, further tightening the supply-demand balance.

The results of the 2025/26 BRA are expected to have profound implications for the PJM market and electricity ratepayers:

1. **Focus on Maintaining Existing Generating Resources:** The sharp increase in capacity prices highlighted the immense tightening of the PJM capacity market, making it paramount to maintain the existing generation fleet while encouraging increased investments in new power plants and transmission projects. However, almost 12,000 MW of primarily coal-fired power plants are scheduled to retire by 2028, with insufficient replacement capacity currently under development.

2. **Impact on Electricity Ratepayers:** The total cost of capacity for the 2025/26 delivery year soared to $14.7 billion, a burden that ratepayers across the PJM footprint will ultimately bear. Rate increases are expected to be uneven, with the most significant impacts likely in deregulated markets served by demand-only utilities. In contrast, vertically integrated utilities in states like Kentucky, Virginia, and West Virginia may see minimal or no impact due to their use of the Fixed Resource Requirement (FRR) Alternative or by bidding nearly the same amount of capacity into the capacity auction as they need to meet their internal load.

3. **Challenges for Future Capacity Auctions:** The current trends in the PJM market, including the ongoing retirement of coal plants and the slow pace of new generating capacity entering the market, suggest that the challenges seen in the 2025/26 BRA may persist or even worsen in future auctions. Without significant changes, such as increased investment in transmission infrastructure or policy adjustments to encourage new generation, the PJM market could face ongoing capacity constraints and escalating costs.

In conclusion, the 2025/26 BRA results signal a pivotal moment for the PJM market, highlighting the urgent need for strategic interventions to ensure future reliability and affordability in the region's electricity supply.

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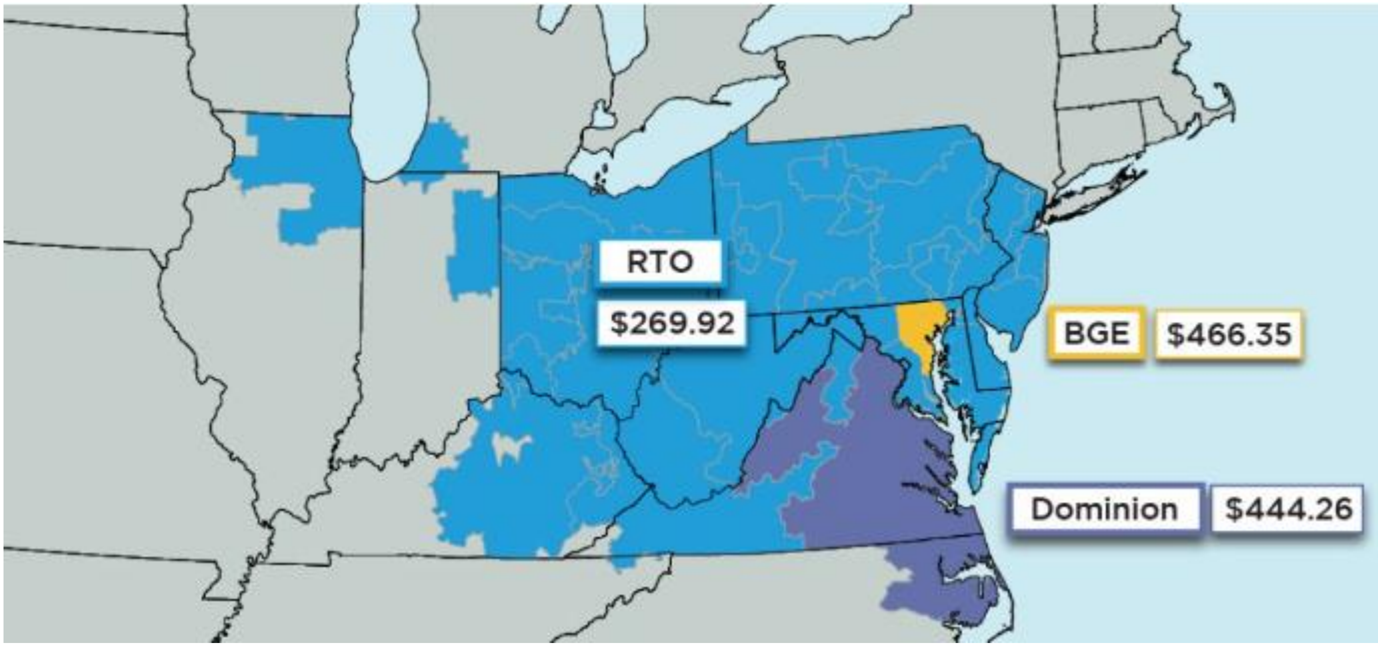
Introduction

On July 30, 2024, PJM released the results of its 2025/26 Base Residual Auction (BRA), which determined capacity prices for the June 1, 2025 – May 31, 2026, period. Despite expecting higher pricing, the results of the 2025/26 BRA shocked the market as the Independent System Operator (ISO) when it announced a capacity price of $269.92 per megawatt-day ($/MW-d) for the Regional Transmission Organization (RTO) footprint, with higher prices of $466.36/MW-d and $444.26/MW-d due to capacity constraints for PJM's Baltimore Gas & Electric (BGE) and Dominion Energy (DOM) zones, respectively. **FIGURE *1*** shows a geographical representation of the 2025/26 BRA results.

FIGURE 1: 2025/26 PJM BRA RESULTS



The capacity prices of the 2025/26 auction represent an almost 10-fold increase over the previous capacity auction for the 2024/25 delivery year, where RTO capacity prices cleared at $28.92/MW-d with BGE clearing at $73.00/MW-d. As a result, the total cost of capacity to PJM members rose from $2.2 billion for the 2024/25 delivery year to $14.7 billion for the 2025/26 delivery year. This report highlights the reasons for the significant increase and the possible implications for the future of the ISO and its stakeholders involved.

Overview of PJM's Capacity Market and Auction Process

Unlike the Electric Reliability Council of Texas (ERCOT), which operates an energy-only electricity market, PJM operates a combination of energy and capacity markets to ensure the reliable operation of electricity service for all members within its footprint while ideally providing financial savings to its utility load-serving entity (LSE) members. While the energy market is generally operated in a day-ahead and real-time operation mode, where electric generators bid into daily energy auctions to meet the forecasted PJM system load, PJM's capacity market generally operates on a multi-year forward basis. Essentially, PJM's energy market ensures the day-to-day reliability of the ISO electricity service, given actual load and generation constraints. In contrast, the capacity market ensures that sufficient electric generating units (EGU) are available during the day-to-day operation of the ISO.

The traditional multi-year lead-time of PJM's capacity market auctions would allow for new EGUs to enter the market should an auction indicate a likely shortfall of capacity during the delivery year in question. However, due to changes in the overall capacity market structure and auction process, while also awaiting confirmation from the U.S. Federal Energy Regulatory Commission (FERC) on these proposed changes, the latest auction for the 2025/26 delivery year was not held until July 2024, less than 12 months before the commencement of the delivery year[1] in question. Possible issues with this condensed capacity auction schedule are discussed later in this report.

Before the auction begins, PJM releases information on BRA planning period parameters that will need to be fulfilled during the auction. These parameters include the forecasted peak load, the installed reserve margin target, and the forecast pool requirement (FPR). All play vital roles in determining the amount of capacity PJM will require to meet its forecasted capacity requirement to ensure reliable electricity service during the 2025/26 delivery year and to satisfy the PJM reliability criterion of a Loss of Load Expectation (LOLE) not exceeding one occurrence in 10 years. Also, before the auction, PJM LSE members notify PJM of their intention to participate in the BRA or to meet their capacity requirements using their own EGUs. This process is also referred to as Fixed Resource Requirement or FRR. During the auction, all PJM generators participating in the BRA offer their electric generating capacity (or load-reducing capability – i.e., demand response (DR) resources) at various price points (in $/MW-d). The offered capacity price of the last EGU is needed to meet PJM's planning period parameters defined before the auction sets the clearing price of the auction. The cleared auction price is then paid to each EGU that cleared the auction during the planning period. Additionally, every resource that cleared the auction now also has a delivery obligation to the market during the planning period, and non-performance triggers substantial financial penalties, as experienced by numerous generators in the fallout of December 2022 Winter Storm Elliott.

Changes to PJM's Capacity Market Prior to the 2025/26 Base Residual Auction

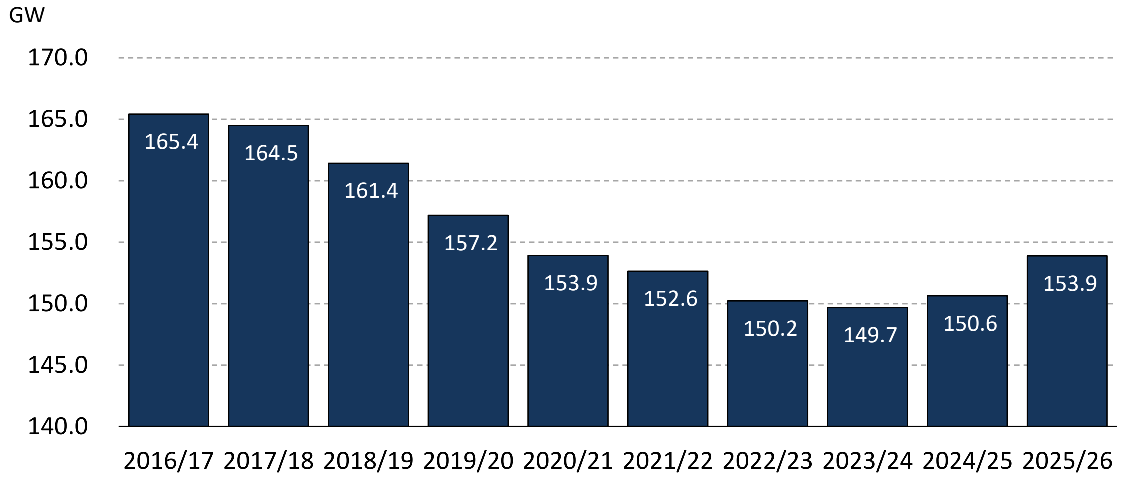
As previously mentioned, PJM's 2025/26 BRA cleared at a capacity price of $269.92/MW-d, representing a 10-fold increase in price over the previous BRA. This substantial increase in capacity price can be attributed to three primary changes PJM made prior to the capacity auction: (1) an increase in forecasted Peak Load, (2) an increase in the target Installed Reserve Margin, and (3) a decrease in Effective Load Carrying Capability (ELCC) factors assigned to the various electric generating or load-reducing resources.

PJM's Increase in Forecast Peak Load and Target Installed Reserve Margin

Prior to the 2025/26 BRA, PJM released the Planning Period Parameters that would need to be met by the upcoming auction. The updated Planning Period Parameters included an increase in forecast peak load from 150,640 MW during the 2024/25 delivery year to 153,883 MW during the 2025/26 delivery year, an increase of over 3,200 MW or 2.2%. **FIGURE *2*** shows the forecast peak load for the last 10 PJM capacity auctions.

[1] PJM's capacity market years operate from June 1 to May 31 of the following year

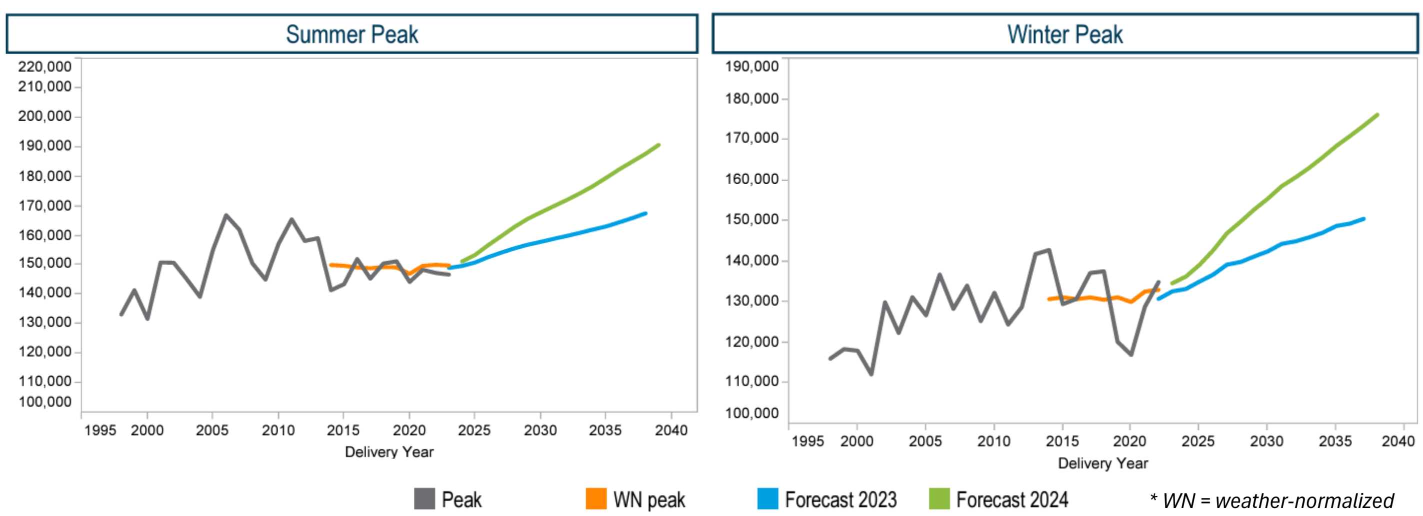
FIGURE 2: PJM FORECAST PEAK LOAD FOR THE LAST 10 CAPACITY AUCTIONS



Source: PJM BRA Planning Period Parameter Documents

After years of declining forecast peak load, PJM's demand forecast has shown a noticeable reversal as the 2025/26 forecast peak load represents a 2.2% increase over the 2024/25 peak load forecast. According to PJM's January 2024 load forecast report[2], the primary drivers in PJM's increased electricity demand forecast were positive shifts in electrification of the transportation sector (i.e., electric vehicles) and a substantial growth in electricity demand from data centers. Specifically, PJM staff adjusted the demand forecast for anticipated point loads due to data center growth in its American Electric Power (AEP), Allegheny Power (APS), DOM, and PSEG (PS) zones. **FIGURE *3*** shows PJM's updated 2024 load forecast for the entire RTO with a comparison to its 2023 load forecast, highlighting the massive electricity demand growth the ISO is now projecting over the next decade.

FIGURE 3: PJM'S 2024 RTO ELECTRIC PEAK LOAD FORECAST



Besides the apparent substantial upward shift in forecasts for both summer and winter peaks across the PJM RTO, it is also worth noting the noticeable increase in weather-adjusted winter peak demand over the last decade, as more states within the PJM footprint pursue more aggressive GHG emission reduction goals and encourage increased switching from fossil fuels (e.g., natural gas and oil) to electricity within the residential and commercial heating sectors. However, previous

[2] https://pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx

winter storms like the December 2022 Winter Storm Elliott[3] or the 2014 Polar Vortex have highlighted the increased vulnerability of the PJM electricity grid during these winter peak load periods.

Besides the forecast peak load, the other notable Planning Period Parameter change from the 2024/25 auction is the Installed Reserve Margin (IRM) and the corresponding Forecast Pool Requirement (FPR). Following the system strains during Winter Storm Elliott in December 2022, PJM proposed to increase its IRM target by 3.1 percentage points to 17.8%. Additionally, PJM changed the methodology for calculating the FPR for the 2025/26 BRA due to changes in the ELCC of its participating resources, as explained later. During the 2024/25 BRA, the FPR was calculated as follows:

*Forecast Pool Requirement (FPR) = (1+IRM) *(1- Pool-Wide 5-Year Average Equivalent Forced Outage Rates (EFORd))*

*2024/25 BRA FPR = (1+14.7%) * (1-5.02%) = 1.0894*

However, for the 2025/26 BRA, PJM changed the formula to the following:

*2025/26 FPR = (1+IRM) * Pool-Wide Accredited Unforced Capacity (UCAP) Factor*

*2025/26 FPR = (1+17.8%)*79.69% = 0.9387*

As a result, the PJM RTO Reliability Requirement (inclusive of all possible FRR resources) for the 2025/26 BRA was 144,450 MW. However, when using the IRM of 14.7% for the 2024/25 BRA, the simple increase in IRM resulted in an increased RTO Reliability Requirement of 3,795 MW. Together, the changes in its peak load forecast and increased IRM resulted in an increased RTO Reliability Requirement of 6,758 MW.

PJM's Capacity Accreditation Changes for the 2025/26 Base Residual Auction

However, arguably, the most significant impact on the 2025/26 BRA results was PJM's capacity accreditation for each auction-participating resource. To account for the differences in available generation capability for different EGUs during peak electricity demand periods during the summer and winter months, PJM (and other ISOs and utilities) adjust the installed capacity (ICAP) by an assumed probability factor of that type of resource not being available during peak demand times. The result is an EGU's unforced capacity or UCAP. Before the 2025/26 BRA, PJM calculated the UCAP for unlimited resources (i.e., dispatchable, long-duration resources) by multiplying its maximum generating capability (i.e., ICAP) by the probability that the resource will be available (1-EFORd)[4]. For variable resources (e.g., wind, solar, battery storage, renewable + battery hybrid projects), PJM uses an Effective Load Carrying Capability (ELCC) analysis to calculate the class-wide resource performance adjustment factor that is used to determine a variable resource's UCAP value. However, in its recent FERC filing, PJM states that *"recent operating experiences such as Winter Storm Elliott have demonstrated that modeling approaches focused on peak load conditions and average generator performance do not fully capture all of the risks that impact resource adequacy needs and resource performance. Therefore, PJM argues that, without enhancements in these areas, the capacity market will provide insufficient incentives to retain and attract sufficient capacity resources necessary to maintain reliability."* As a result, PJM proposed to FERC, which FERC ultimately granted, to *"extend ELCC*

[3] https://www.evainc.com/press-releases/eva-winter-storm-elliott-report/
[4] https://pjm.com/directory/etariff/FercOrders/7145/20240130-er24-99-000.pdf

accreditation to all Generation Capacity Resources." **FIGURE *4*** shows the resulting changes in capacity accreditation by resource type.

FIGURE 4: ELCC CLASS RATINGS BY BRA YEAR

	2024/25 ELCC Class Ratings	2025/2026 BRA ELCC Class Ratings	Change in Value
Onshore Wind	21%	35%	+14%
Offshore Wind	47%	60%	+13%
Fixed-Tilt Solar	33%	9%	-24%
Tracking Solar	50%	14%	-36%
Landfill Intermittent	61%	54%	-7%
Hydro Intermittent	36%	37%	+1%
4-hr Storage	92%	59%	-33%
6-hr Storage	92%	67%	-25%
8-hr Storage	92%	68%	-24%
10-hr Storage	92%	78%	-14%
Demand Resource	100%	76%	-24%
Nuclear	98%	95%	-3%
Coal	89%	84%	-5%
Gas Combined Cycle	95%	79%	-16%
Gas Combustion Turbine	89%	62%	-27%
Gas Combustion Turbine Dual Fuel	89%	79%	-10%
Diesel Utility	95%	92%	-3%
Steam	87%	75%	-12%

EFORd used based on NERC GADS '22 data

As shown in **FIGURE *4***, single-fuel natural gas combustion turbines have seen the most considerable reduction in ELCC or capacity accreditation for the 2025/26 BRA due to their poor performance during previous extreme cold weather events such as Winter Storm Elliott. Conversely, nuclear, coal, and diesel utility (i.e., internal combustion engines) have seen only a minimal reduction in capacity accreditation due to their proven performance during Winter Storm Elliott and other peak demand periods. On the variable resource side, solar and battery storage resources saw a significant reduction in their ELCC ratings due to the ELCC analysis focus on past performance during winter peak demand periods.[5]

In its 2025/26 BRA Results Report, PJM provides a detailed overview of the amount of UCAP offered and cleared by resource type[6], adjusted for ELCC values shown in **FIGURE *4***. Below, **FIGURE *5*** combines the UCAP values shown in PJM's

[5] Winter peak demand periods usually occur during early morning hours around sunrise when solar output is minimal, while wind generation is generally higher than during summer peak demand hours during the early afternoon. Also, battery storage resource performance has been poorer during extreme cold weather events than during peak summer heat events.

[6] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx Table 6

report with the ELCC values shown in **FIGURE *4*** to highlight the impact of PJM's change in ELCC accreditation for variable and unlimited generating resources.

FIGURE 5: IMPACT OF PJM'S CAPACITY ACCREDITATION CHANGES

	UCAP Cleared in 2025/26 BRA+FRR	2025/2026 BRA ELCC Class Ratings	2024/25 ELCC Class Ratings	Cleared UCAP using 2024/25 ELCC	Difference (UCAP - MW)
Onshore Wind	1,676	35%	21%	1,006	670
Offshore Wind	-	60%	47%	-	-
Fixed-Tilt Solar	-	9%	33%	-	-
Tracking Solar	1,337	14%	50%	4,775	(3,438)
Landfill Intermittent	1,184	54%	61%	1,337	(153)
Hydro Intermittent	5,361	37%	36%	5,216	145
4-hr Storage	14	59%	92%	22	(8)
6-hr Storage	-	67%	100%	-	-
8-hr Storage	-	68%	100%	-	-
10-hr Storage	-	78%	100%	-	-
Demand Resource	6,342	76%	100%	8,345	(2,003)
Nuclear	30,549	95%	98%	31,514	(965)
Coal	30,081	84%	89%	31,872	(1,791)
Gas Combined Cycle*	42,472	79%	95%	51,074	(8,602)
Gas Combustion Turbine*	17,628	62%	89%	25,305	(7,677)
Gas Combustion Turbine Dual Fuel	-	79%	89%	-	-
Diesel Utility	2,986	92%	95%	3,083	(97)
Steam*	6,253	75%	87%	7,254	(1,001)
Total	**145,884**			**170,803**	**(24,919)**

*uses EIA 860 data to split natural gas by technology type

EFORd based on NERC GADS '22 data

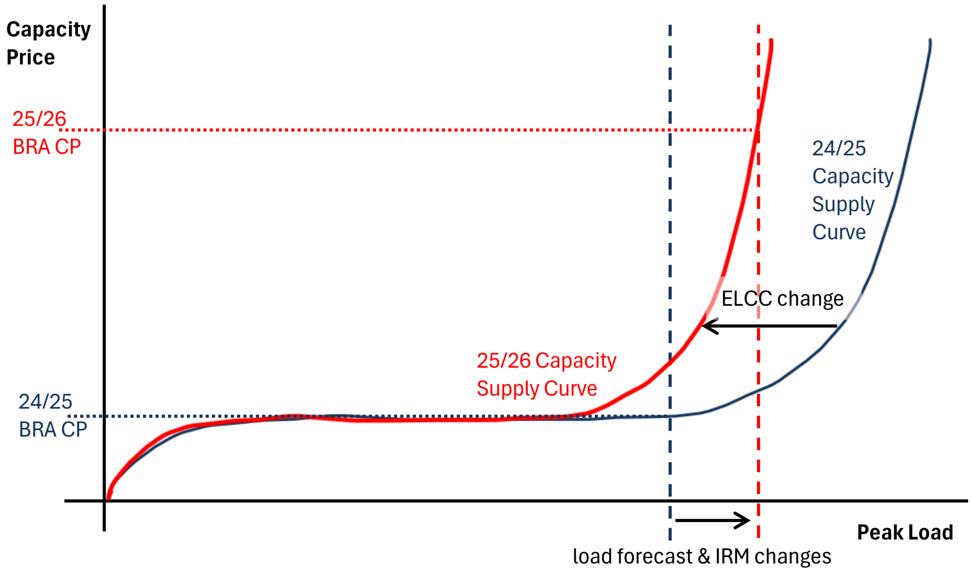
As shown in **FIGURE *5***, simply by changing the capacity accreditation for each resource type participating in the BRA, PJM effectively reduced the amount of accredited unforced capacity by almost 25,000 MW or 17% of the 2025/26 cleared unforced capacity. All in all, PJM's three changes in forecast peak load, increased IRM, and expanded ELCC rating to all EGUs created a swing of 31,677 MW from the 2024/25 to the 2025/25 capacity auction, excluding any changes in resource retirements or additions.

Results & Impacts of PJM's 2025/26 Base Residual Auction

Auction Results

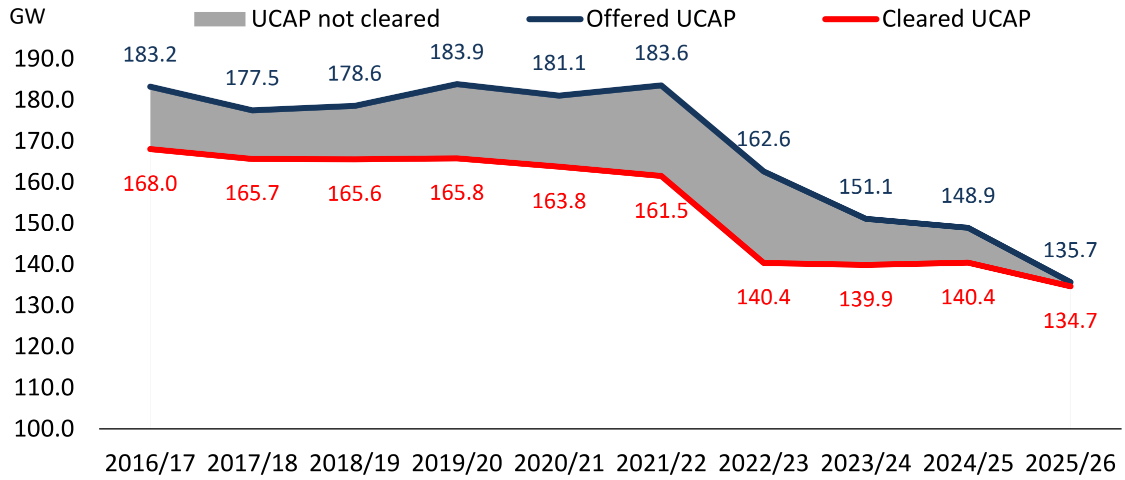
As previously mentioned, PJM's 2025/26 BRA cleared at a capacity price of $269.92/MW-d, representing a 10-fold increase in price over the 2024/25 BRA clearing price of $28.92/MW-d, driven primarily by the changes in forecast peak load, installed reserve margin, and resource capacity accreditation (i.e., ELCC). **FIGURE *6*** visually represents the impact of the changes discussed previously on the 2025/26 BRA capacity clearing prices.

FIGURE 6: IMPACT OF CHANGES TO PJM CAPACITY MARKET PRE-2025/26 BRA



Additionally, Dominion Energy (re)joining the RPM after previously utilizing PJM's Fixed Resource Requirement (FRR) Alternative, a decrease in overall supply from retirements (actual retirements plus must-offer exceptions for future retirements), change in status from capacity resource to energy-only, and must-offer exceptions for exports also provided upward pressure on the capacity clearing price during the 2025/26 BRA. Besides the high auction clearing price, it is also worth noting that virtually all offered unforced capacity in the RPM cleared the auction. **FIGURE *7*** shows the offered and cleared RPM unforced capacity for the last ten BRAs.

FIGURE 7: OFFERED VERSUS CLEARED CAPACITY IN LAST 10 PJM CAPACITY AUCTIONS



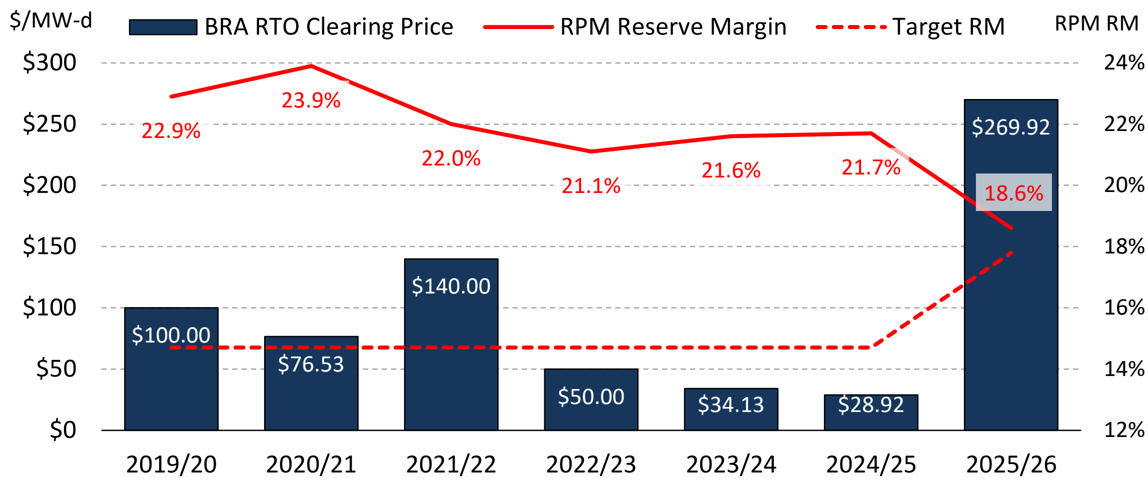
Source: PJM BRA Results

Historically, before the 2025/26 BRA, about 9% of the offered UCAP did not clear the auction. In the 2025/26 BRA, that percentage fell to less than 1%, as almost all offered capacity cleared. As per PJM's report, only 942 MW of wind, 54 MW of aggregate resources, 21 MW of demand response, and 4 MW of hydro did not clear the 2025/26 auction.

Correspondingly, as illustrated in **FIGURE *7***, almost all of the 2025/26 BRA capacity supply was needed to meet the Planning Period Parameters defined prior to the auction, resulting in the ISO's highest capacity price in its history. Likewise, the actual resulting RPM reserve margin barely exceeds the increased IRM target of 17.8%, as defined prior to the auction.

The BRA clearing prices, actual RPM reserve margins, and the IRM targets for the last seven auctions are shown in **FIGURE *8***.

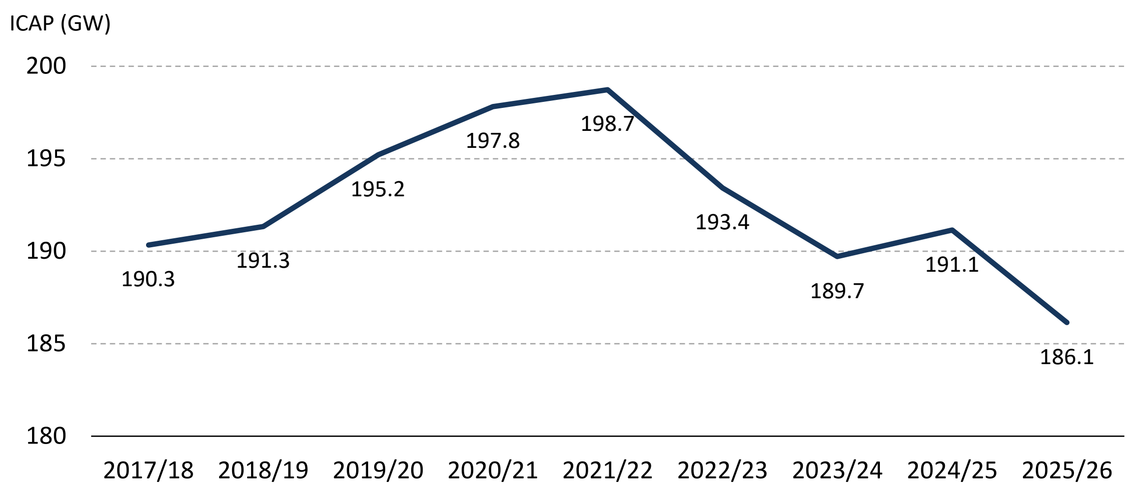
FIGURE 8: PJM BRA CLEARING PRICES, RPM RESERVE MARGINS & RESERVE MARGIN TARGETS



Source: PJM BRA Results

One of the prevailing causes for the decline in actual reserve margin is the continued decline in internal PJM generating capacity due to plant retirements, primarily coal plants.

FIGURE 9: INTERNAL PJM GENERATING CAPACITY (ICAP)

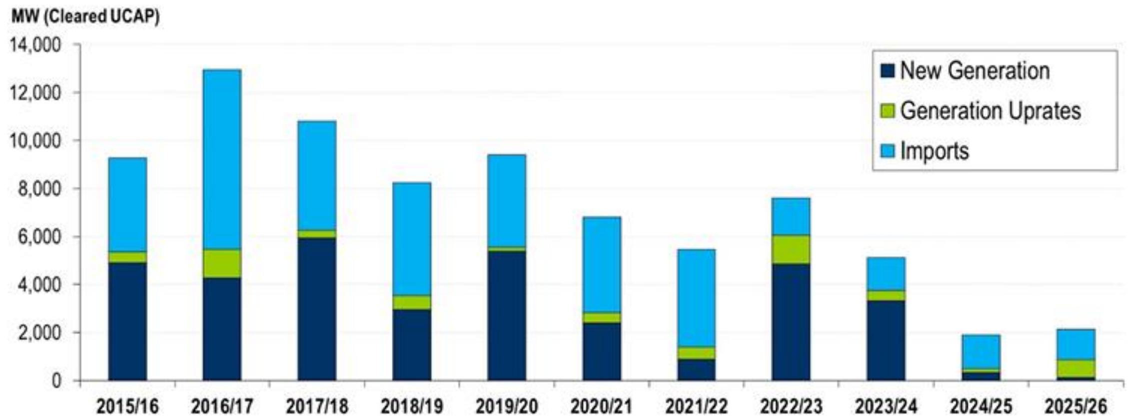


Source: PJM BRA results

As shown in **FIGURE *9***, PJM's internal generating capacity has been on a continuous decline (except for the 2024/25 Delivery Year) since the 2021/22 Delivery Year. It has since declined over 12 GW in just four auctions due to coal retirements across the PJM footprint as federal and state regulations such as the EPA's Coal Combustion Residuals (CCR) Rule or Effluent Limitation Guidelines (ELG) or the Regional Greenhouse Gas Initiative (RGGI) make it increasingly unprofitable for coal plants to continue operating. Prevailing PJM capacity prices of less than $100/MW-d were not enough to incentivize coal plant owners and operators to make the necessary investments to comply with these federal and state regulations.

The issue is compounded by the lack of new generating resources being offered in the PJM capacity auction, as shown in **FIGURE *10***.

FIGURE 10: CLEARED MW (UCAP) BY NEW GENERATION/UPRATES/IMPORTS BY DELIVERY YEAR

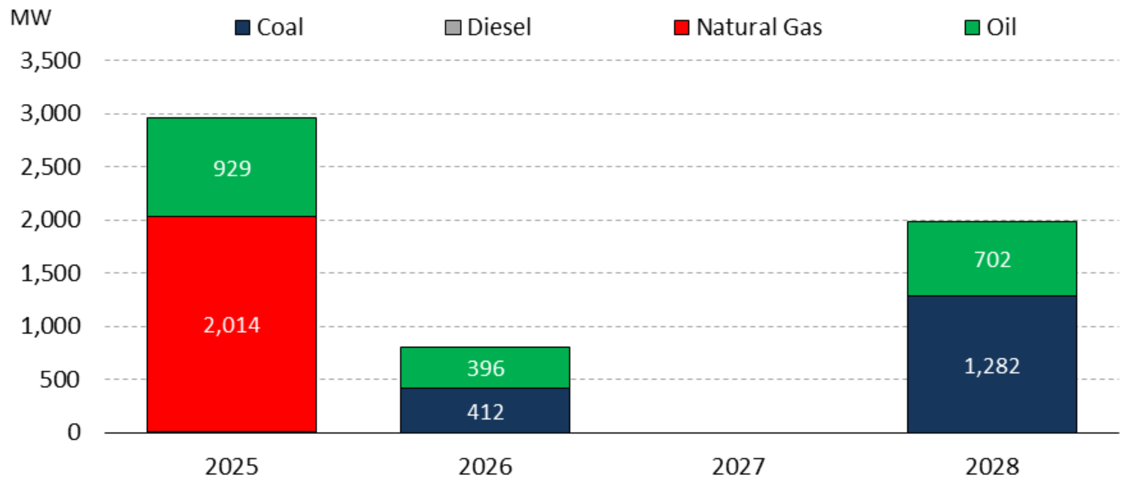


The 2025/26 BRA saw the lowest amount of new generating capacity offered and cleared in a PJM capacity auction, with only 110.3 MW of new capacity clearing the auction. 753.8 MW of unit uprates and 1,268.5 MW of imports also cleared the 2025/26 BRA auction. With the next auction currently scheduled for December 4, 2024, and a likely continued increase in forecast load, a swift and considerable change of the trend in net capacity decline in the PJM footprint is needed to meet the capacity requirements of the 2026/26 Base Residual Auction.

Auction Impacts on Existing and New PJM Generating Resources

As outlined above, one of the prevailing issues is the continued decline in generating capacity across the PJM footprint. However, when looking at upcoming scheduled PJM power plant deactivations versus the amount of capacity that has cleared the PJM interconnection queue, it is unlikely that PJM's capacity woes will subside in the near future. **FIGURE *11*** summarizes the current PJM Deactivation List by fuel type over the next four years.

FIGURE 11: CURRENT PJM DEACTIVATION NOTICES BY YEAR



Source: PJM Deactivation List (as of 8/15/24)

Currently, over 5,700 MW of installed capacity is slated for retirement over the next four years. PJM has already identified likely reliability issues for 2,400 MW of the 5,700 MW and has placed the five EGUs, Indian River 4 (coal), Brandon Shores 1 & 2 (coal), and Wagner 3 & 4, under reliability-must-run (RMR) contracts. However, RMR units are barred from participating in PJM's capacity auction as their compensation is provided through the RMR contract between the plant operator and PJM. For another 2,300 MW of capacity, PJM's reliability impact analysis is still ongoing, while PJM found no reliability impact for the remaining 1,000 MW of scheduled capacity retirements.

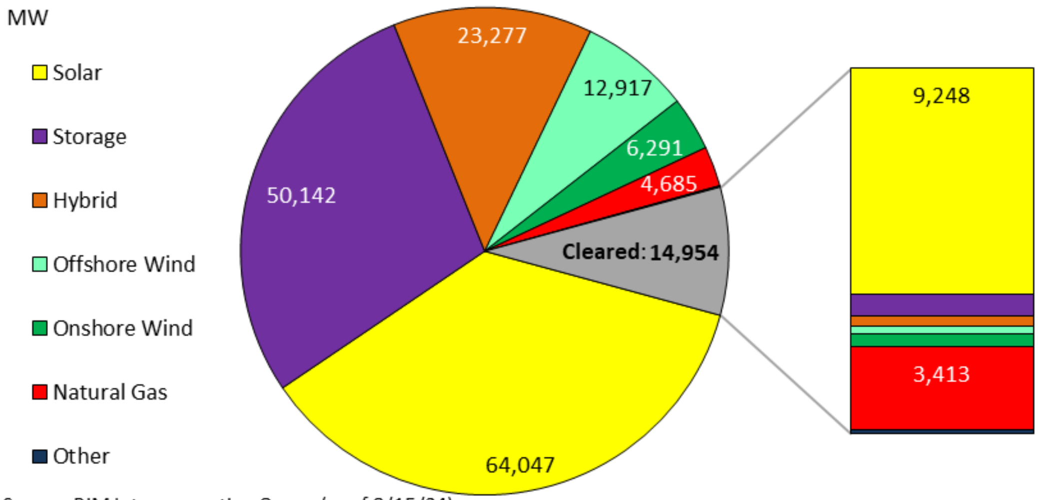
However, according to EVA's Power Plant Tracking System, eight more coal-fired EGUs are scheduled for closure by the end of 2028, totaling almost 6,000 MW of installed capacity, as shown in **FIGURE *12***.

FIGURE 12: PJM COAL PLANTS SCHEDULED FOR RETIREMENT BY 2028

Plant Name	Owner	State	ICAP (MW)	Year-End Retirement
Kincaid	Vistra	IL	554.0	2027
Kincaid	Vistra	IL	554.0	2027
Cardinal	Buckeye Power	OH	585.0	2028
Cardinal	Buckeye Power	OH	620.0	2028
Miami Fort	Vistra	OH	510.0	2027
Miami Fort	Vistra	OH	510.0	2027
Rockport	AEP	IN	1,300.0	2028
Rockport	AEP	IN	1,300.0	2028
		Total (MW) =	**5,933.0**	

Preventing any additional near-term power plant retirements across the PJM footprint will be paramount to meeting the capacity requirements of future PJM capacity auctions, especially given the status of PJM's current interconnection queue, which is shown in **FIGURE *13***.

FIGURE 13: ACTIVE & CLEARED PJM INTERCONNECTION REQUESTS



Source: PJM Interconnection Queue (as of 8/15/24)

As of August 15, 2024, there are roughly 176 GW of PJM interconnection requests, of which about 15 GW so far have been cleared by PJM and are currently in various states of advanced development. Of the approximately 162 GW of uncleared capacity in PJM's interconnection queue, only 4.7 GW or less than 3% are so-called unlimited generating resources. The remaining 97% are variable energy resources such as on and offshore wind, solar, and short-term battery storage projects. Furthermore, of the 4,700 MW of natural gas-fired capacity actively seeking interconnection, only four projects totaling 3,700 MW would be considered new power plants. In contrast, the remaining 32 projects are simple uprates at existing natural gas power plants. Additionally, one of the four new projects is Competitive Power Venture's proposed 2,100 MW natural gas combined cycle, which is planned to be equipped with carbon capture and sequestration (CCS) technology and would be the only new power plant complying with EPA's finalized updated New Source Performance Standards (NSPS) for baseload stationary combustion turbines.[7]

Additionally, the 15 GW of currently cleared interconnection requests are also dominated by variable energy resources, especially solar, which accounts for over 61% of all cleared capacity. Of the 3,400 MW of natural gas-fired capacity cleared for interconnection, only one project, the 850-MW Trumbull Energy Center in Lordstown, Ohio, is scheduled to come online by 2026. The remaining four natural gas-fired power plant projects are scheduled to come online in either 2027 (ESC's Harrison County CC) or 2028 (Maple Creek Energy, Sycamore Riverside Energy Center, and Dominion Energy's Chesterfield Energy Reliability Center). Due to PJM's ELCC adjustments, which negatively impacted natural gas-fired and solar power plants, the 15 GW of currently cleared interconnection capacity will likely be insufficient to offset the loss of capacity should the retirement of the 6 GW of coal plants by 2028 go forward as scheduled.

Lastly, EPA's recently finalized updated NSPS for stationary combustion turbines has put into question the economic viability of new baseload natural gas combined cycle plants for the foreseeable future. As per EPA's NSPS, new natural gas combined cycle plants planning to operate at an annual capacity factor greater than 40% will be required to meet a CO_2 emission rate of 100 lbs per MWh-gross by 2032, achievable through either 96% hydrogen co-firing or deploying 90% CCS. Both technologies continue to be greatly unproven in today's U.S. electricity market. Only operating at an annual capacity factor of less than 40% would forego the emission rate requirement only achieved by using CCS or hydrogen co-firing. For reference, PJM's existing natural gas combined cycle fleet has been operating at an annual capacity factor of greater than 60% in 2023 and 2024 year-to-date. Due to the technological and permitting difficulties associated with the unproven technologies of 90% CCS or 96% hydrogen co-firing, no amount of capacity payment will be sufficient to incentivize new

[7] EPA's updated NSPS for stationary combustion turbines requires an emission rate equivalent to deploying 90% CCS at the plant for all baseload (i.e., CF > 40%) by 2032.

baseload natural gas combined cycle plants. To meet future capacity requirements, future PJM generators will likely be focused on expanding PJM's existing stationary simple cycle combustion turbines and limiting their annual utilization rate to less than 40%.

Impact on PJM Electricity Ratepayers

The record-high capacity clearing price of $269.92/MW-d will result in a total capacity cost of over $14.7 billion to PJM members, which ratepayers across the PJM footprint will have to cover. However, it is worth noting that not all ratepayers across PJM will see the same impact on their future electricity bills. For example, ratepayers in service territories of vertically integrated regulated utilities in states like Kentucky, West Virginia, and Virginia will either see no or minimal impact since their utility either did not participate in the 2025/26 BRA by utilizing the FRR Alternative (e.g., Indiana-Michigan Power or Appalachian Power) or have bid into the auction enough generating capacity to meet their own load (Monongahela Power or Virginia Electric Power), where their cost of capacity will largely be offset by the capacity revenue received from the BRA, both of which will be passed through to their electric ratepayers.

On the other hand, ratepayers serviced by demand-only utilities, which closed most of their existing generating capacity to take advantage of the deregulation of electricity generation across PJM and the resulting low-cost capacity provided by the PJM market, will likely see the most significant impact on their electric bills. For example, Exelon, owner of six utilities with 10.5 million customers in Delaware, Illinois, Maryland, New Jersey, Pennsylvania, and the District of Columbia, estimates that the latest capacity auction for the 2025/26 delivery year will likely lead to double-digit rate increases for some of its utility subsidiaries, including Baltimore Gas and Electric, where capacity prices cleared at $466.36/MW-d due to capacity constraints.[8] When and by how much the electricity bills for PJM ratepayers will increase will depend on each state's Public Utilities Commission and their respective rules and regulations regarding the electric rate adjustments based on changes in capacity cost.

Conclusion

Although the final capacity clearing price of PJM's 2025/26 Base Residual Auction sent shockwaves through the ISO, its stakeholders, and the U.S. electricity market at large, the result was not surprising to many market observers and analysts who have been following the recent market developments closely. For years, PJM and its member utilities enjoyed a massive surplus of generating capacity across the PJM footprint, fueled by the natural gas power plant build boom following the low-cost natural gas price environment brought on by the Shale Gas Revolution in 2009. Even though coal plant retirements, forced by increasingly restrictive federal and state environmental regulations, continued to accelerate, the immense surplus of generating capacity and actual RPM reserve margins well above 20% did not have PJM members worried about a future potential capacity shortfall.

The Polar Vortex of 2014 and Winter Storm Elliott in 2022 highlighted the vulnerability of an electricity market that largely exchanged the reliability of power plants with onsite fuel storage, such as coal and oil-fired power plants for natural gas ones, many of which do not have onsite fuel storage, rely on just-in-time fuel delivery, something that is not far from guaranteed as shown during these extreme winter weather events. These weather events have provided an increased realization of the vulnerabilities of an electricity market that relies on natural gas-fired power plants for more than 43% of its electricity needs. It is worth noting that following Winter Storm Elliott, PJM has taken commendable steps to minimize the future likelihood of loss of load events in these peak load scenarios by adjusting the ELCC for all generating resources and valuing the reliability provided by resources that were available during Winter Storm Elliott while also increasing the Installed Reserve Margin target.

In addition to the reduced real-life performance of many EGUs across PJM during extreme weather events such as Winter Storm Elliott, PJM also has to manage the immense sudden load growth expected to come from data center construction

[8] https://www.utilitydive.com/news/exelon-pjm-capacity-auction-bge-talen-data-center/723163/

in multiple zones across PJM, especially in Northern Virginia and Chicago, following the recent technological boom in Artificial Intelligence computing and machine learning. For example, Exelon's ComEd utility has over 5 GW of data center projects currently in the engineering phase, with another 13 GW of potential data center projects interested in locating to the ComEd service territory. Dominion Energy also expects its data center load to grow to over 15 GW by 2030, potentially rendering PJM's demand forecast conservative.

However, as highlighted in this report, the number of projects currently cleared to connect to the PJM power grid is insufficient even to offset the massive amount of coal retirements scheduled to disconnect by 2028, let alone meet any increased electricity demand from data centers or electric vehicles. Therefore, every upcoming power plant retirement should face heightened scrutiny and analysis to ensure adequate electric generating capacity in the near term while allowing more power plant projects to enter and clear the interconnection queue to meet the capacity needs of the PJM power grid in the long term. Additionally, a substantial investment in PJM's transmission grid is likely needed to connect and distribute the future more decentralized capacity of solar, wind, and energy storage resources.

Glossary of Terms

Term	Definition
Effective Load-Carrying Capability (ELCC)	ELCC measures a resource's contribution to reliability based on the incremental quantity of load that can be satisfied by adding the resource to the grid
Equivalent Forced Outage Rate (EFORd)	The percent of scheduled operating time that a unit is out of service due to unexpected problems or failures AND cannot reach full capability due to forced component or equipment failures
Fixed Resource Requirement (FRR)	FRR is an alternative method for an eligible load-serving entity to meet a fixed resource requirement with its own capacity resources as opposed to having PJM procure capacity resources on the load-serving entity's behalf in capacity auctions
Forecast Pool Requirement (FPR)	The Forecast Pool Requirement is calculated based on the IRM and the pool-wide average equivalent demand forced outage rate (EFORd)
Installed Capacity (ICAP)	Also known as nameplate capacity in PJM, ICAP is the intended full-load sustained output of an electric generator
Installed Reserve Margin (IRM)	IRM is the amount of the generating capacity in excess of the expected load, calculated to satisfy the loss of load expectation, typically 1 day in 10 years.
Unforced Capacity (UCAP)	UCAP is installed capacity rated at summer conditions that are not, on average, experiencing a forced outage or forced de-rating. Effective with the 2018/2019 Delivery Year, UCAP is equal to the Nominated Value (i.e., ICAP) of that resource multiplied by the Forecast Pool Requirement (FPR) or ELCC.