August 30, 2024

*Via email*

PJM Board of Managers
Mark Takahashi, Chair
Manu Asthana, President and CEO
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

**Re: Urgent Reforms to the PJM Capacity Market Regarding Reliability Must Run Units**

Dear Chairman Takahashi and President Asthana,

The undersigned organizations respectfully request that the PJM Board take immediate action to protect ratepayers throughout the PJM region—and especially in the BGE Load Deliverability Area (LDA)—from unjust and unreasonable prices in the PJM capacity market caused by the non-participation of power plants operating under Reliability Must Run arrangements (RMR). As a recent report demonstrates, the failure of two power plants slated for operation under RMR arrangements starting at the beginning of the delivery year of the just-completed base residual auction (BRA) to participate in that auction could have caused excessive capacity costs of roughly $5 billion.[1] To prevent similarly unjust and unreasonable prices in upcoming capacity auctions, we request that the Board urgently institute a Critical Issue Fast Path process to develop rules that will require the capacity value of RMR units to be considered in the capacity market, effective for the next BRA. If necessary to have time to institute the appropriate changes, the Board may need to delay the auction currently scheduled for December 2024. While several of our organizations have stressed the importance of returning to three-year-forward auctions as soon as possible, we agree that it is critical to revise these rules before another auction commits consumers to paying yet another year of excessive and unreasonable capacity prices.

As the attached report from Synapse Energy Economics on behalf of the Maryland Office of People's Counsel demonstrates, the record-setting price spike in the most recent

[1] *See* Synapse Energy Economics, Inc., *Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland* (Aug. 2024), https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-13%20Final%20corrected%208-29-24.pdf?ver=fHKa18_idtwi4Rm4OeK-7A%3d%3d.

PJM capacity auction resulted in large part from the fact that power plants operating under RMRs are not required to—and did not—participate in the capacity market. The most recent capacity auction resulted in a more than 800 percent increase in capacity prices, with RTO-wide prices surging more than nine-fold from $29/MW-day to $270/MW-day, and with prices reaching caps in the constrained BGE LDA of $466/MW-day. However, as the Synapse report shows, if two power plants slated for operation under RMRs during the delivery period covered by the auction—the Brandon Shores and Wagner plants—had participated in this most recent capacity auction, the resulting prices would have been far lower, under certain assumptions regarding bids and clearing prices. The BGE LDA would not have reached its price cap and would instead have cleared along with the rest of the RTO at a price of $163.46/MW-day. In other words, the RMR units' non-participation in the capacity market cost consumers roughly $5 billion.

The record-setting prices stemming from RMR units' non-participation in the capacity auction are unjust and unreasonable. The absence of any requirement for RMR units to participate in the capacity market, or for PJM to consider RMRs in determining capacity needs, unreasonably forces consumers to pay twice for reliability—once to keep RMR units online and again in a capacity market that ignores these units' continued operations.[2]

The lack of any requirement for RMR units to participate in the capacity market renders the market vulnerable to unreasonable outcomes. In the most recent auction, the exclusion of capacity from just two RMR units, the 1,282 MW (nameplate capacity) Brandon Shores plant and the 841 MW (nameplate) Wagner plant, created a $5 billion windfall for generation owners at consumers' expense. And as the Synapse report shows, not offering these two units allowed their owner, Talen Energy, to pocket $360 million more than it otherwise would have from the capacity market.

Moreover, the market's vulnerability to unreasonable outcomes driven by RMR unit non-participation will likely become an increasingly severe problem. PJM anticipates roughly 40 gigawatts (GW) of retirements by 2030. Without significant reforms, PJM lacks adequate procedures to prevent the need for RMRs for many of these retiring units. Hence, RMR generators may look in the future to exploit gaps in the capacity market rules by not bidding into the market, bringing about costly results for customers unless PJM takes swift action.

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[2] *See New York Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076 (2016), at P 82, (aff'd on rehearing at *New York Indep. Sys. Operator, Inc*., 161 FERC ¶ 61,189 (2017), at PP 54-63) (finding that RMR units should participate in the capacity market as price takers because if they failed to clear, "ratepayers will pay twice—once for the cost of the RMR agreement, and again for the generator that otherwise would not have cleared the market").

RMR units' non-participation in the capacity market also causes the market to send inaccurate price signals. The temporarily higher prices that result from non-participation of these units signal a degree of capacity scarcity that does not exist, since RMR units are operational during the delivery year in question and in many circumstances available to PJM during capacity emergencies.[3] Furthermore, these price spikes are unlikely to drive significant additional investment in new generation since developers would expect the prices to drop once the needed transmission upgrades are complete, and because of the well-documented delays in PJM's interconnection queue. Such price spikes are unreasonable when they do not reflect the real-world supply-demand balance and are unlikely to prompt near-term resource adequacy improvements.

Other RTO/ISOs prevent these issues by requiring RMR units to participate in their capacity markets. For example, New York ISO and ISO New England both require RMR units to participate in its capacity market as price-takers.[4] Similarly, California ISO requires RMR units to participate in its resource adequacy procurement mechanism.[5] Hence, PJM's failure to require RMR units to participate in its capacity market makes it an outlier among RTOs.

Unless PJM takes swift action, the serious defects in PJM's capacity market stemming from not including RMR units will likely result in unjust and unreasonable prices in subsequent auctions currently scheduled for December 2024 and June 2025. Interconnection of new generation remains slow in PJM, with the queue still badly clogged and no new interconnection requests being processed until at least 2026. Because new generation cannot come online quickly, the high capacity market prices are not an effective signal for new entry but instead a windfall for the owners of existing generation.

For all these reasons, we respectfully request that the PJM Board take immediate action to revise its capacity market rules to require the capacity market to reflect continued operation of RMR units, as supply, decreased capacity need, or other equivalent means. The Board should institute a Critical Issue Fast Path process to develop these rules, while minimizing any delay to the upcoming capacity auction currently

[3] *See, e.g.*, *ISO New England*, 179 FERC ¶ 61,139 (2022), at PP 50, 52 (finding that excluding resources that will be available from the capacity market forces consumers to buy unnecessary capacity and results in prices that do not send efficient entry and exit signals); *ISO New England Inc.*, 165 FERC ¶ 61,202, at P 83 (2018).

[4] *New York Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076 (2016), at P 82; *ISO New England Inc.*, 165 FERC ¶ 61,202, at P 83; *id.* at P 87 ("ISO-NE has demonstrated that retaining a resource outside of the FCA would not account for its contribution to meeting ISO-NE's resource adequacy needs, would result in procuring excess capacity, and would distort the capacity price.").

[5] *California Indep. Sys. Operator*, 168 FERC ¶ 61,199 at PP 7, 72–76 (2019).

scheduled for December 2024. Without such reforms, the capacity market will be unable to deliver just and reasonable results.

We respectfully request that the PJM Board address this issue swiftly—and by no later than September 20, 2024. We hope to collaborate with the PJM Board and PJM staff on prompt reforms to address this serious flaw in the capacity market design through a Critical Issue Fast Path process.

Sincerely,

David S. Lapp
People's Counsel
Maryland Office of People's Counsel

*/s/ Ruth Ann Price*
Ruth Ann Price
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# Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland

OPC
OFFICE OF PEOPLE'S COUNSEL
State of Maryland

August 2024

(corrected 8/29/24)

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*Report prepared for the Maryland Office of People's Counsel by Synapse Energy Economics, Inc., a research and consulting firm specializing in economic and policy research, modeling, and analysis to provide electric sector solutions.*

# GLOSSARY

| | | |
|---|---|---|
| BRA | Base Residual Auction | The PJM capacity auction, called the Base Residual Auction, procures "capacity" power supply resources in advance of the delivery year to meet electricity "resource adequacy" needs in the PJM service area, which includes all or part of 13 states and the District of Columbia. Auctions are usually held three years in advance of the delivery year. Due to recent changes in market design, among other factors, PJM held the most recent BRA, in July, 2024, for the delivery year starting June 1, 2025 (the BRA 25/26), with the auction held only about one year in advance of the beginning of the delivery year. PJM currently intends to conduct subsequent BRAs on an accelerated basis to enable returning to the 3-year forward schedule. The BRA is the first auction, in a cycle of several auctions for each delivery year underPJM's Reliability Pricing Model (RPM), or capacity market, where the majority of the RPM capacity is procured for a particular delivery year. |
| CETL | Capacity Emergency Transfer Limit | Capacity Emergency Transfer Limit (CETL) is the capability of the transmission system to support deliveries of electric energy to a given area (or LDA, see below) experiencing a localized capacity emergency as determined in accordance with the PJM Manuals. |
| CETO | Capacity Emergency Transfer Objective | The amount of electric energy that a given area (a LDA) must be able to import in order to remain within a loss of load expectation of one event in 25 years (or its expected unserved energy (EUE) equivalent under the new PJM reliability metrics starting with the 25/26 BRA) when the area is experiencing a localized capacity emergency. |
| CONE | Cost of New Entry | CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out energy and ancillary service (E&AS) margins from CONE. This metric is used in calculating the VRR Curve (see below) which is used to define the administrative cost cap to the BRA. |
| CSRR | Cost of Service Recovery Rate | One of two options RMR (see below) owners can elect for cost recovery for an RMR agreement. See text for more details on the CSRR method. |
| CTR | Capacity Transfer Rights | A method of allocating the economic value of transmission import capability that exists into a constrained Locational Deliverability Area (LDA) to Load Serving Entities (LSEs). |
| DACR | Deactivation Avoidable Cost Rate | One of two options RMR (see below) owners can elect for cost recovery for an RMR arrangement. See text for more details on the DACR method. |
| DY | Delivery Year | The PJM capacity auction procures commitments for a delivery year, beginning June 1 and ending May 30th. The RPM was and is intended to provide for the conduct of each annual capacity auction (or BRA) three years in advance of the beginning of the running of the delivery year commitment procured through the auction. Currently due to slippage resulting from multiple causes, PJM just completed the most recent BRA, in July, 2024, for the 25/26 delivery year, which begins at the same time |

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| | | (June 1, 2025) as the scheduled beginning of the Brandon Shores and Wagner RMR arrangements. The 24/25 delivery year was already procured through a previously completed auction. |
| E&AS | Energy & Ancillary Services Revenues | Revenues from the energy and ancillary services markets, which are unit-specific. E&AS are historically netted out of Market Seller Offer Caps, and/or Net Cost of New Entry calculations. |
| EFORd | Equivalent Demand Forced Outage Rate | A measure of the probability that a generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. |
| ELCC | Effective Load Carrying Capability | ELCC provides a way to assess the capacity value (or reliability contribution) of a resource (or a set of resources) that is tied to the loss-of-load probability concept. ELCC can be defined as a measure of the additional load that the system can supply with a particular generator of interest, with no net change in reliability. ELCC can be based on any reliability metric (e.g., Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), or Expected Unserved Energy (EUE)). PJM shifted from its prior use of LOLE to an EUE metric for the most recently completed BRA (2025/2026) which was conducted in July, 2024 |
| EUE | Expected Unserved Energy | This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. |
| FERC | Federal Energy Regulatory Commission | The federal agency that regulates wholesale electric power sales and transmission rates. |
| ICAP | Installed Capacity | A MW value based on the summer net dependable capability of a unit and within the capacity interconnection right limits of the bus to which it is connected. |
| IMM | Independent Market Monitor | PJM's Independent Market Monitor is responsible for guarding against the exercise of market power in PJM's markets and assisting in the maintenance of competitive and nondiscriminatory markets in PJM. The IMM operates independently from PJM staff and members to objectively monitor, investigate, evaluate, and report on PJM’s markets. Monitoring Analytics serves as PJM’s independent market monitor. |
| IRM | Installed Reserve Margin | Percentage value used to establish the level of installed capacity resources that provide an acceptable level of reliability. |
| LDA | Locational Deliverability Area | Sub-regions of PJM’s “footprint” used to evaluate locational constraints of the electric grid. An LDA is an area or zone within the wholesale electric markets administered by PJM, in which local effects of transmission, load, and generating resources are separately accounted for in the operation of PJM’s markets. In this report, costs described as allocated to or incurred by a LDA mean costs flowed through to the end-use customers located within that LDA. Maryland is covered by all or portions of 4 LDAs: the BGE LDA, roughly equal to BGE’s retail service area (and entirely within Maryland); DPL-South (inclusive of the Maryland eastern shore and southern Delaware); Pepco LDA, covering the retail service areas of |

| | | |
|---|---|---|
| | | Pepco (both Maryland and DC) and SMECO; and the APS LDA (including Potomac Edison's Maryland service area and extending to the retail service areas of PE's affiliates in West Virginia and Southwest Pennsylvania). The cost impacts analyzed in this report focus on those anticipated for Maryland customers.. |
| LOLE | Loss of Load Expectation | Loss-of-load expectation (LOLE) defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, only once in 10 years. This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. |
| MSOC | Market Seller Offer Cap | PJM uses Market Seller Offer Caps to ensure that resources are submitting competitive offers into the capacity market, thus preventing sellers from exerting market power and setting artificially high prices. A resource's MSOC is equivalent to the costs it would avoid if it retired or if it did not clear in the capacity market and did not operate for the delivery year. It is the minimum capacity price a resource needs to take on a capacity obligation and continue operations for another year. |
| RMR | Reliability Must-Run | A generating unit slated to be retired by its owners but that is needed for reliability reasons. Typically, PJM requests that the unit remain operational beyond its proposed retirement date until transmission upgrades are completed. |
| RPM | Reliability Pricing Model | PJM's capacity market design that includes a series of auctions to satisfy the reliability requirements of the PJM region for a Delivery Year. The majority of capacity is procured in the first auction for a particular delivery year, which is known as the Base Residual Auction. This auction is intended to be conducted three years in advance of a given delivery year. The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning process to ensure the reliability of the PJM region for future years. |
| RTO | Regional Transmission Organization | The organization that coordinates, controls, and monitors a multi-state electric grid. In this report, RTO refers to PJM Interconnection, LLC (or PJM) which operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. |
| UCAP | Unforced Capacity | The megawatt (MW) value of a capacity resource in the PJM Capacity Market. PJM currently uses different methods to accredit the amount of UCAP specific resource types may offer into the PJM capacity market but was shifted to a marginal ELCC approach for the recently completed BRA (for delivery year 2025/2026). |
| VRR Curve | Variable Resource Requirement | A downward sloping demand curve used in the conduct and settlement of the BRA, both PJM wide and for individually constrained LDAs, that relates the maximum price for a given level of capacity resource commitments relative to reliability requirements. |

*All definitions above are sourced from the PJM website and its educational materials, as well the North American Electric Reliability Corporation (NERC).*

# 1. EXECUTIVE SUMMARY

PJM Interconnection LLC (PJM), the entity that operates the electricity grid for the Mid-Atlantic region and nearby states, administers a capacity market to assure adequate generation capacity to meet peak loads and reliability standards.[1] As part of its responsibilities, PJM procures capacity through annual competitive auctions. On July 30, 2024, PJM released results for its latest capacity market base residual auction (BRA) for the 2025/2026 delivery year that runs from June 1, 2025 to May 31, 2026. The results showed a more than 800 percent increase in system-wide prices relative to the prior BRA for the 2024/2025 delivery year, a price spike unprecedented in PJM. Across the entire PJM footprint, beginning June 1, 2025, these capacity prices will result in a total annual cost to electric customers of $14.7 billion, a substantial increase from the $2.2 billion in capacity costs in the 2024/2025 delivery year. These surging prices are driven primarily by (1) increases in load, (2) various market rule changes that, among other effects, modify how supply (e.g., generation) is valued in the capacity market, and (3) a reduction in capacity market supply due to plant retirements and retirement-related "reliability-must-run" (RMR) arrangements. The Maryland Office of People's Counsel commissioned Synapse Energy Economics (Synapse) to analyze the likely impacts of the changes in the capacity market and these RMR arrangements on the rates paid by Maryland's electric utility customers.

The capacity market auction is conducted for the entire PJM footprint. Capacity-constrained regions, known as locational deliverability areas (LDAs) can sometimes have separate, higher capacity prices from the RTO as a whole. These LDAs exhibit constraints when comparing the local load within the LDA, the local generation within the LDA, and the PJM-administered transmission system's ability to transfer power into the LDA. The different, typically higher clearing prices for the constrained LDAs reflect the tighter balance of load, local generation, and transmission transfer capacity into the LDA when compared with broader areas of the PJM footprint.

Maryland is included in all or portions of four LDAs:

- *Baltimore Gas and Electric (BGE LDA)*, the only LDA entirely located in Maryland, which is comprised of Baltimore Gas and Electric's (BGE) Maryland service territory;
- *Allegheny Power System (APS LDA)*, which covers portions of Maryland, Pennsylvania, Virginia, and West Virginia, including the service territory of Potomac Edison, which serves customers in Western Maryland, and various municipal utilities in the APS LDA footprint;

[1] PJM administers other product markets, in addition to the capacity market, that are paid for by electric customers. PJM administers the "energy" market for the power consumed by customers continuously over time. It also plans and procures the transmission system within its footprint. In relative terms, the costs of the energy and capacity markets and those due to transmission costs are the three principal cost components of wholesale electric costs borne by electric customers. In 2023, they comprised 62%, 8% and 27%, respectively, on average across the PJM footprint of wholesale electric costs. With the results of the recent 25/26 BRA discussed further in the report, capacity costs beginning June 1, 2025 will comprise nearly 27% of total wholesale costs (up from 8% in 2023), assuming energy and transmission costs remain near 2023 levels. PJM Members Committee, Markets Report, MC Webinar, July 22, 2024. Item 05A - 2 - Market Operations Report Appendix. Available at: https://www.pjm.com/committees-and-groups/committees/mc.aspx

- *Delmarva Power South (DPL-South LDA)*, which covers Maryland and Delaware portions of the Delmarva Peninsula, including Maryland utility Delmarva Power; and
- *Potomac Electric Power (Pepco LDA)*, which covers portions of Maryland and Washington, D.C., including Maryland utilities Potomac Electric Power (Pepco) and Southern Maryland Electric Cooperative (SMECO).

Except for the BGE LDA, the Maryland LDAs cover multiple jurisdictions and encompass other utilities within them. For example, the Pepco LDA includes SMECO, which means that the customer impacts discussed in this report for the Pepco LDA apply equally to SMECO customers. Similarly, the impacts on DPL-South LDA apply to customers of Delmarva Power & Light as well as municipal and cooperative electric utilities on Maryland's Eastern Shore.

Over the past several years, the BGE LDA has been capacity-constrained and has seen higher prices relative to other LDAs. Once again, in the latest base residual auction, for the 2025/2026 delivery year, the BGE LDA was capacity-constrained, and this time it cleared at its maximum possible price: $466/MW-day. This is a six-fold increase from the 2024/2025 BGE LDA BRA clearing price of $73/MW-day. The APS, DPL-South, and Pepco LDAs all cleared at the same clearing price as the full RTO, which saw prices of $270/MW-day, a nine-fold increase from the previous year's results ($29/MW-day). Electric customers pay for capacity at these prices, meaning that the results of this auction will be seen on the bills of electric customers in Maryland starting in 2025 or beyond. In the BGE LDA, the total increase in customer costs from the 2024/2025 to the 2025/2026 BRA auction is $504 million. For the average residential customer in the BGE LDA, this means an additional $16 per month on their electric bills for at least a year (Table 1). Similarly, average residential customers in APS, DPL-South, and Pepco LDAs will see an additional $18, $4, and $14 per month, respectively, on their electric bills starting in 2025 or soon after (Table 1).

Table 1. Bill and Rate Impacts of the 2025/2026 capacity market relative to 2024/2025, for the BGE LDA and the Maryland portion of APS, DPL-South, and Pepco LDAs

| **Maryland LDAs** | **Monthly Bill Change (%)** | **Additional Costs on Monthly Bills ($)** | |
|---|---|---|---|
| | All | Residential | Commercial |
| BGE LDA Customers | 14% | $16 | $170 |
| APS LDA Customers (Maryland only) | 24% | $18 | $81 |
| DPL-South LDA Customers (Maryland only) | 2% | $4 | $16 |
| Pepco LDA Customers (Maryland only) | 10% | $14 | $163 |

*Source: See description in text.*

The most notable driver behind BGE LDA's record high capacity price is the removal of four generating units from the capacity market, starting in the 2025/2026 delivery year. Specifically, in 2023, Talen Energy, the owner of the aging, large, fossil fuel-fired power plants—Brandon Shores Units 1 & 2 and Wagner Units 3 & 4—announced its intent to retire (or deactivate) the plants, effective June 1, 2025. The units are in the BGE LDA, an area already known for its constrained transmission capacity. PJM determined their retirement could cause grid reliability issues until new transmission solutions can be implemented to bring in electricity from other areas and to address power quality issues arising when the power plants are retired.

While the transmission solutions are being built (that address the reliability issues arising from Talen plant retirements), PJM is arranging for the continued operation of these four units past their proposed retirement date of June 2025. The plants would operate under a “reliability must run,” or “RMR” arrangement and receive payments—funded through customer rates—outside of the competitive wholesale power markets. RMR service is intended to ensure grid reliability until the transmission grid can be enhanced to eliminate the grid reliability concerns associated with the plant retirements.

Under these RMR arrangements, ratepayers will pay the power plants’ owner compensation for the continued operation of the plants under a separate “out of market” regime administered by PJM. Importantly, these RMR units do not participate in the capacity market as supply-side resources, dramatically reducing supply in the already-constrained BGE LDA. In fact, without these units participating in the capacity market in 2025/2026, less than 10 percent of BGE’s cleared capacity was from generation within the BGE LDA, pushing the clearing price for the BGE LDA to the capacity price maximum for the LDA.

The capacity shortfall in BGE LDA from the conversion of Brandon Shores and Wagner to RMR service also likely had spillover effects into the RTO as a whole, increasing the RTO-wide clearing price and impacting customers throughout the region. To determine the effects, we conducted a counterfactual analysis of clearing prices in PJM using assumptions described in more detail in section 3.3. We found that if Brandon Shores and Wagner RMR units had remained as supply-side resources in the capacity market under those assumptions, the RTO as a whole would have cleared at $163.46/MW-day. At that price, electric customers across the RTO would save over $5 billion in that delivery year. Further, comparing this counterfactual analysis to the actual results of the capacity market and Talen’s proposed RMR, we found that Talen’s revenues for the 2025-2026 delivery year are $360 million higher than what they would have been had Talen’s units participated in the capacity market.

Furthermore, the BGE LDA is now so constrained that the cleared resources and imported capacity did not meet the LDA’s reliability requirement for the 2025/2026 delivery year in this auction. The reliability requirement is the target amount of capacity required to meet PJM’s reliability standard, i.e., a loss of load probability of no more than once in 25 years for LDAs. In the 2025/2026 delivery year, there is a capacity shortfall of 176 MW relative to the reliability requirement, suggesting that the probability of reliability issues for the BGE LDA could increase starting June 2025, potentially further impacting customers in addition to higher electric rates.

Because the Talen units are within the capacity-constrained zone of the BGE LDA (located entirely within Maryland), and because the RMR cost allocation follows the cost allocation for the transmission solutions that will eliminate the RMR need, Maryland customers will pay most of these out-of-market RMR costs. Currently, PJM projects that the planned transmission solutions will be completed by December 2028, after which the RMR units would no longer be needed. Until that time—or later, if the transmission solutions take longer to construct—customers of local utilities in these constrained areas will pay millions of dollars for RMR service to the power plants’ owner.

Talen Energy is seeking to recover annual fixed costs of over $215 million for Brandon Shores’ and Wagner’s RMR arrangements, combined. These RMRs could cost Maryland’s residents and businesses over $629 million through 2028, the earliest by which the RMR arrangements could end. BGE customers can expect to pay an estimated 74 percent—or roughly $159 million per year—of these costs. As a result, BGE customers could see their bills increase by approximately 5 percent, resulting in an average residential bill increase of $5 per month due to RMR costs alone (Table 2). When combined with the incremental impact of the capacity market costs (Table 1, above), electric customers in the BGE LDA could see average bill increases of $21 per month.

Table 2. Summary of costs associated with Brandon Shores and Wagner RMRs for BGE

| BGE LDA Costs | Annual Costs to BGE Customers | Monthly average residential bill increase ($/month) | Annual average residential bill increase ($/year)* | Time frame of cost impacts |
|---|---|---|---|---|
| RMR Costs | $159 million | $5 | $59 | June 2025 – December 2028 (or longer with construction delays, ongoing reliability issues, etc.) |
| Capacity Market Costs *(Incremental)* | $504 million | $16 | $188 | June 2025 – May 2026 (likely similar impact from June 2026 – May 2028, unless additional capacity becomes available) |
| Total Incremental Costs | $663 million | $21 | $247 | June 2025 – May 2026 (likely similar impact from June 2026 – May 2028, unless additional capacity becomes available) |

*Source: See description in text.*
** Numbers are higher than monthly average multiplied by 12 months because of rounding.*

These RMR cost impacts are uncertain. For one, OPC is litigating the amount of recoverable RMR costs before FERC. Second, there is uncertainty in the length of time that PJM will use these units for RMR service. PJM has indicated that it requires Brandon Shores to provide RMR service until December 2028, when it projects that the transmission solutions needed to eliminate the need for the Brandon Shores RMR units will be completed, while the Wagner plant may need to continue providing RMR service beyond 2028. However, if there are major changes to load or other factors that could affect reliability in the region, PJM may determine that Brandon Shores and Wagner need to continue providing reliability service beyond the currently planned December 2028 date. Lastly, the projected completion date of December 2028 for these transmission solutions is highly uncertain; there could be delays in the project construction and execution, further imposing RMR costs on electric customers. If the transmission projects are not complete by the end of 2028, and/or the continued operation of the RMR units are required beyond December of that year, the RMR costs for electric customers would necessarily increase.

The length of time that PJM, and especially BGE customers, will continue to see elevated prices is also uncertain. The next PJM capacity market auction, for the 2026/2027 delivery year, is set to occur in December 2024, less than 5 months from the recently completed 2025/2026 auction, making it unlikely that there will be any major increases in available supply. Given the long wait times in processing the interconnection queue (delaying the interconnection of new generating resources to the grid to replace the RMR units) and the uncertainty around queue reform, it is unlikely that enough new generation will be under way before December 2024 and online by June 1, 2026 (the start of the 2026/2027 delivery year) to substantially alleviate the very high prices seen for the 2025/2026 BRA. In the case of the BGE LDA, these interconnection queue backlogs make it unlikely that any major generation will be interconnected before the end of 2028, the earliest date for ending the Brandon Shores' and Wagner's RMR arrangements. Thus, the strong price signal sent by the high capacity market prices in the BGE LDA (and the RTO as a whole) may not induce timely new generation into service within the LDA before the completion of the transmission lines that end the need for these RMRs (or to help alleviate prices seen across the region). Instead, the clogged queue could lock in a windfall for the existing generating units continuing to operate in the BGE LDA and across the PJM region generally.

This report and its calculations of prices and bill impacts is based on the best information available at the time of publication. The nature of the report is necessarily forward looking and depends on the assumptions described within. Because PJM is reviewing its market rules and because of changing economic conditions, actual future market prices and bill impacts could be different.

# 2. PJM'S RELIABILITY MUST-RUN

To understand the impacts to Marylanders of the anticipated RMR arrangements, one needs an understanding of how RMR arrangements work in PJM. This section provides background on the power plant units at issue and describes how RMR costs are allocated to different locational deliverability areas (LDAs).[2] Finally, we describe how, within PJM, RMRs typically interact with wholesale capacity and energy markets.

## 2.1. Background

Reliability must-run service is a status applied to a generating unit that enters into an arrangement with PJM to remain online beyond its slated retirement date to maintain grid reliability. RMRs are arrangements a generator owner and PJM enter into for continued operation of the generator in exchange for payments outside of the competitive wholesale power market. They are referred to as "Part V Reliability Service" in the PJM tariff.[3] Typically, PJM requests that the RMR unit remain operational beyond the generation plant owner's proposed retirement date, until completion of the transmission upgrades that PJM has deemed

[2] An LDA is an area or zone within the wholesale electric markets administered by PJM, in which local effects of transmission, load and generating resources are separately accounted for in the operation of PJM's markets. In this report, costs described as allocated to or incurred by a LDA mean costs flowed through to the end use customers located within that LDA. Maryland is covered by all or portions of 4 LDAs—the BGE LDA, roughly equal to BGE's retail service area (and entirely within Maryland); DPL-South, inclusive of the Maryland eastern shore and southern Delaware; the Pepco LDA, covering the retail service areas of Pepco (both Maryland and DC) and SMECO; and the APS LDA, including Potomac Edison's Maryland service area and extending to the retail service areas of PE's affiliates in West Virginia and Southwestern Pennsylvania. The cost impacts analyzed in this report focus on those anticipated for Maryland customers, although the increases described impacting the cross-jurisdictional LDAs will also adversely affect customers in the other jurisdictions included in these LDAs.

[3] OATT Part V.

necessary to resolve the grid reliability deficiencies which would be caused when and if the plant is retired. Out-of-market solutions, such as RMR service arrangements, limit the effectiveness of the PJM markets and can lead to high costs for consumers. PJM has engaged in 17 RMR arrangements since they were first introduced in PJM in 2005.[4]

Indian River 4 ("IR4"), a 410-MW coal plant owned by NRG Power Marketing, is the only unit currently providing RMR service in PJM and illustrates RMR arrangements. NRG announced its intent to retire IR4 as of June 1, 2022. Before that planned retirement date, PJM deemed the plant's continued operation necessary for grid reliability. Under PJM's plans, the transmission builds to address reliability issues resulting from the retirement of IR4 require a capital investment of $51 million,[5] while NRG's RMR revenue requirements for IR4, as reflected in a contested settlement agreement currently pending before FERC for approval, are $228 million over the  proposed term of the RMR arrangement (June 1, 2022 to Dec. 31, 2026).[6] NRG originally proposed fixed RMR revenue requirements of $357 million; these were contested at FERC by some PJM customer advocates and representatives, including the Maryland Office of People's Counsel. The lower RMR costs, as reflected in the contested settlement pending at FERC, are the result of that litigation and settlement, assuming approval of the settlement by FERC.

This paper focuses on the cost impacts of the future RMR arrangements that PJM is entering into with Talen Energy for its Brandon Shores and Herbert A. Wagner (Wagner) power plants.

- ***Brandon Shores*.** On April 6, 2023, PJM received Talen Energy's deactivation notice for Brandon Shores, a 1,282 MW coal-fired power plant in Maryland's BGE zone, proposing the retirement of the plant on June 1, 2025.[7] PJM assessed the deactivation, and stated that without Brandon Shores, severe voltage drop and thermal violations could occur across seven PJM zones, which could lead to a widespread voltage collapse in Baltimore and the surrounding areas.[8] PJM has said that these reliability issues can only be addressed through needed transmission system upgrades. The Grid Solutions Package addressing these shortcomings was approved by the FERC in November 2023 and is slated to be in service by December 31, 2028.[9] For the interim period until the transmission upgrades are complete, PJM requested that Brandon Shores remain in

[4] Deactivation Enhancements Senior Task Force, February 15, 2024 Meeting, Agenda Item 3 – RMR History. Monitoring Analytics, LLC.

[5] Public Service Commission of Maryland, Order 90950, December 5, 2023. Case No. 9698. The Application of Delmarva Power & Light Company for a Certificate of Public Convenience and Necessity to Rebuild the Vienna-Nelson 138 kV Transmission Line in Dorchester and Wicomico Counties, Maryland.

[6] NRG Power Marketing LLC, Docket No. ER22-1539-002, NRG Business Marketing LLC, Docket No. ER23-2688-002, Settlement Agreement and Offer of Settlement, filed April 2, 2023. The IMM and Maryland Office of People's Counsel are contesting this settlement agreement, and FERC action on the settlement filing is still pending. PJM has indicated that the transmission solutions required to eliminate the need for the IR4 RMR are ahead of schedule, and could be complete by the end of 2024. Devin Leith-Yessian, "PJM OC Briefs: July 11, 2024, Indian River Transmission Upgrades Projected to be Complete One Year Ahead of Schedule July 14, 2024." July 15, 2024, RTO Insider. Available at: https://www.rtoinsider.com/83230-pjm-oc-071124/

[7] Federal Energy Regulatory Commission, November 9, 2023. Order on Cost Allocation Report and Tariff Revisions (ER23-2612-001 and 002), 185 FERC ¶ 61,107 (2023). Available at: https://www.pjm.com/directory/etariff/FercOrders/7022/20231108-er23-2612-001.pdf.

[8] Ibid.

[9] Ibid.

service as an RMR resource to relieve the reliability issues. On April 18, 2024, Talen Energy submitted a tariff filing at FERC for Brandon Shores' RMR Arrangement.[10]

- ***Herbert A. Wagner*.** On October 16, 2023, Talen filed a deactivation notice for the Wagner power plant, an 841 MW generator located in the BGE LDA.[11] Wagner burns coal, gas, oil, and diesel, and has four units: Wagner 1, Wagner CT, Wagner 3, and Wagner 4.[12] It is slated for retirement on June 1, 2025,[13] the same day as Brandon Shores' deactivation date. In January 2024, PJM identified grid reliability violations resulting from the deactivation of Wagner 3 and 4; PJM requested to use those two units as RMR units.[14] On April 18, 2024, Talen Energy submitted a tariff filing at FERC for Wagner's RMR Arrangement.[15]

## 2.2. RMR Costs

### RMR Costs for Brandon Shores and Wagner (Initial Filing)

A unit remaining in service under an RMR arrangement has two options for cost recovery: (1) the Deactivation Avoidable Cost Rate (DACR),[16] and (2) the Cost of Service Recovery Rate (CSRR).[17] Talen Energy has elected to use the CSRR approach for RMR cost recovery for both Brandon Shores and Wagner. This approach is designed to "recover the entire cost of operating the generating unit," during the RMR service period, whereby the generator owner must file a rate schedule with FERC.[18]

[10] FERC Docket No. ER24-1790-000, FERC Generated Tariff Filing. April 18, 2024. Brandon Shores LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1790. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5176.

[11] Talen Energy. October 16, 2023. Notice of Deactivation Date for H.A. Wagner 1,3,4 & CT under H.A. Wagner LLC. Available at: https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/wagner-deactiviation-notice.ashx

[12] PJM Generation Deactivations. Available at: https://www.pjm.com/planning/service-requests/gen-deactivations

[13] Talen Energy. October 16, 2023. Notice of Deactivation Date for H.A. Wagner 1,3,4 & CT under H.A. Wagner LLC. Available at: https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/wagner-deactiviation-notice.ashx

[14] Transmission Expansion Advisory Committee, January 9, 2024. Available at: https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240109/20240109-item-02---generation-deactivation-notification-update.ashx

[15] FERC Docket No. ER24-1787-000, FERC Generated Tariff Filing. April 18, 2024. H.A. Wagner LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1787. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5128.

[16] The DACR is a formulaic rate designed to permit the recovery of a unit's avoidable costs of continued operations, plus an incentive adder. These avoidable costs are defined as "incremental expenses directly required for the operation of a generating unit" and include "project investments" (capital expenditures needed to keep the plant operating) of up to $2 million. The incentive adder escalates for each year of service (10 percent of expenses in the first year, 20 percent in the second year, 35 percent in the third year, and 50 percent in the fourth year and beyond). If the owner of an RMR unit decides to continue operations after the RMR arrangement term ends, the tariff requires that project investments that were required for RMR service be repaid to PJM.

[17] More information on the two cost recovery approaches can be found at: Deactivation Enhancements Senior Task Force, October 12, 2023. IMM State of the Market report discussion of Part V (RMR) issues. Available at: https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_DESTF_Memo_re_RMR_20231012.pdf

[18] Deactivation Enhancements Senior Task Force, October 12, 2023. IMM State of the Market report discussion of Part V (RMR) issues. Available at: https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_DESTF_Memo_re_RMR_20231012.pdf

On April 18, 2024, Talen Energy submitted tariff filings at FERC for the RMR Arrangement of Brandon Shores and Wagner, which include provision for the recovery of Talen Energy's requested level of fixed costs for the RMR units, and the units' variable costs of operation. The initial terms of both RMR arrangement tariff filings extend to December 2028, after which PJM anticipates transmission solutions should be in place to eliminate the need for RMR service.[19] However, there is significant uncertainty around this date, as there are numerous factors that could delay the construction and completion of these transmission solutions. Table 3, below, presents the RMR costs as described in the initial Talen Energy filings at FERC.

Table 3. Initially filed costs of Brandon Shores and Wagner RMR Arrangements

| Generator | MW | Annual RMR Cost ($ millions) | RMR Cost for Whole Term ($ millions) |
|---|---|---|---|
| **For Brandon Shores** (units 1 & 2) | 1,282 | $175 | $629 |
| **Wagner** (units 3 & 4 only) | 702 | $40 | $145 |
| **Combined Total for Brandon Shores and Wagner** | **1,984** | **$215** | **$774** |

*Notes: These are total RMR fixed costs, not costs for Maryland only, for June 2025 to December 2028. Cost data from tariff filings, FERC Docket No. ER24-01790-000 (Brandon Shores) and FERC Docket No. ER24-01787-000 (Wagner), April 18, 2024.*

The cost recovery under a CSRR approach is subject to litigation by intervening stakeholders in a proceeding before FERC; the final cost recovery amount, approved by FERC, may be lower than the originally requested amount as a result of that litigation (or as determined in a settlement). Historically, final RMR costs are on average 25 percent less than the initial filing for plants using CSRR.[20] For instance, Indian River 4 (or IR4), described above as the only unit currently providing RMR service in PJM, used the CSRR approach. Its owner, NRG Power Marketing, initially proposed an RMR cost of $520/MW-day.[21] As a result of litigation at FERC and as incorporated into a proposed settlement filed at FERC, IR4's revenue requirements for RMR service are $333/MW-day.[22] This revenue requirement remains subject to challenge by the Maryland OPC and PJM's Independent Market Monitor and is pending a FERC decision. The comparison between the initial filing and the litigated outcome over the history of RMRs in PJM is useful, but not dispositive of predicting the particular outcome in any RMR proceeding litigated at FERC, given the widely varying specific circumstances and levels of cost support across each of the RMR proceedings.

In addition, total whole-term costs, as presented in Table 3, depend on timely completion of PJM's planned transmission solutions on or before the planned date of December 31, 2028. The

[19] The end date or Wagner's RMR arrangement is less certain; PJM may require Wagner to continue RMR service beyond December 2028 (even if Brandon Shores' arrangement terminates on that date as currently planned).

[20] Based on a simple average in $/MW-day across all RMR Arrangements that started June 1, 2011 or later. RMR cost data from Deactivation Enhancements Senior Task Force, February 15, 2024 Meeting. Agenda Item 3 – RMR History. Monitoring Analytics, LLC.

[21] Ibid.

[22] NRG Power Marketing LLC, Docket No. ER22-1539-002, NRG Business Marketing LLC, Docket No. ER23-2688-002, Settlement Agreement and Offer of Settlement, filed April 2, 2023.

transmission solutions, totaling $726 million in capital expenditures,[23] may carry potential risks of delay that are beyond the scope of our analysis. If they are not completed on time, however, it is likely PJM would seek to extend the RMR terms beyond 2028, adding further RMR costs for customers. The RMRs could also be extended as a result of changes in load forecasts; if forecasts go up, PJM could determine the RMRs are needed past 2028 to mitigate related reliability impacts.

### Cost Allocation to Maryland LDAs

As described in PJM's tariff, RMR costs are allocated to the "load in the Zone(s) of the Transmission Owner(s) that will be assigned financial responsibility for the reliability upgrades necessary to alleviate the reliability impact that would result from the Deactivation of the generating unit."[24] FERC approved the Brandon Shores Grid Solutions Package at the end of 2023. The package includes transmission upgrades PJM deemed necessary to maintain reliability following the deactivation of Brandon Shores.[25] We assumed Brandon Shores RMR costs are allocated proportionally to the cost allocation of that same Grid Solutions Package, which affects all Maryland LDAs (BGE, Pepco, DPL-South, and APS)[26] (Table 4). PJM has not indicated what transmission upgrades are required to alleviate the reliability impact of Wagner. Without more accurate information, we assumed that RMR costs for the Wagner plant would also be allocated according to the approved Brandon Shores Grid Solutions Package.[27]

Table 4. Annual and total Brandon Shores and Wagner RMR costs for Maryland

| **Maryland LDAs** | **Maryland Customers' Share of RMR Costs** | **Annual RMR Cost to Maryland LDAs** ($ millions) | **RMR Cost for Whole Term for Maryland LDAs** (June 2025 – Dec 2028) ($ millions) |
|---|---|---|---|
| APS LDA Customers (Maryland only) | 0.1% | $0.3 | $1.1 |
| BGE LDA Customers | 74% | $159 | $569 |
| DPL-South LDA Customers (Maryland only) | 1% | $2.5 | $9 |
| Pepco LDA Customers (Maryland only) | 7% | $14 | $50 |
| **Maryland Total** | **81%** | **$176** | **$630** |

*Notes: All costs are presented in real 2024 dollars. See description in text for cost allocations.*

[23] Transmission costs for the Brandon Shores Deactivation Grid Solutions, provided by Strategen Consulting, Inc. to Synapse on March 7, 2024.

[24] OATT Part V - 120 Cost Allocation.

[25] Federal Energy Regulatory Commission, November 9, 2023. Order on Cost Allocation Report and Tariff Revisions (ER23-2612-001 and 002).

[26] Transmission grid solution cost allocation to LDAs was provided by Strategen Consulting, Inc. to Synapse on March 7, 2024.

[27] To allocate costs, Synapse used the transmission grid solution cost allocation to LDAs provided by Strategen Consulting, Inc. on March 7, 2024.

The BGE LDA is located entirely in Maryland, bearing 74 percent of total costs of the RMR arrangements across PJM. As shown in Table 4, Maryland customers in the Pepco LDA pay for 7 percent of the PJM total, while customers in the remaining two Maryland LDAs (APS, DPL-South) pay less than 1.5 percent of the costs together. In total, Maryland customers pay roughly 81 percent of the total RMR costs for Brandon Shores (Units 1 and 2) and Wagner (Units 3 and 4)—$176 million per year and $630 million over 3.5 years. As discussed, final revenue requirements of these RMR units may be lower as a result of litigation at FERC.

## 2.3. Treatment of RMRs in the Capacity and Energy Markets

PJM's capacity market is meant to secure capacity commitments—in megawatts (MW)—from generation plant owners, with the intention of securing future reliability. Like any market, prices set by the capacity market depend on buyers and sellers. For example, a smaller number of bidders offering fewer megawatts of capacity into the capacity market lowers supply and could increase prices paid by wholesale buyers—and ultimately by utility retail customers. As further explained below in Section 3.1, PJM's capacity market prices are set in an annual auction and are based on supply (generation plant owner bids)[28] and reliability requirements. The clearing price, or the intercept point between supply and demand, is the price that is paid to all generation plant owners that successfully cleared in the market.

Brandon Shores and Wagner have participated in the capacity market and are committed to provide capacity through to their proposed deactivation dates of June 1, 2025. RMR unit participation in the capacity market, however, depends on the unit's specific RMR arrangement with PJM.[29] Although PJM has designated RMR units to be needed for grid reliability purposes, PJM has not required them to make commitments in the capacity market. PJM and the IMM informed us that nearly all, if not *all*, of the past 17 RMRs have not participated in PJM's capacity market, the Reliability Pricing Model (RPM).[30] Neither Brandon Shores nor Wagner participated in the most recent 2025/2026 capacity market auction and are not expected to participate in future auctions. As discussed in Section 3.3 below, their absence affected the capacity market auction and clearing price for the delivery year 2025/2026 in the BGE LDA, where they are located,[31] and very likely the capacity price for the entire RTO footprint.

For an LDA that is already constrained, such as the BGE LDA—and without additional transmission upgrades or new generation to address constraints—if a unit no longer provides supply in the capacity market, clearing prices are pushed upwards. BGE LDA cleared at its maximum price for the 2025/2026 delivery year, evidence of this upward push on clearing prices. A higher capacity price provides a market signal to generators, incentivizing new generation in that zone. Yet when combined with the out-of-market cost of the RMR itself, the elevated capacity clearing price ultimately costs utility customers in that LDA.

PJM can dispatch and schedule Brandon Shores (Units 1 and 2) and Wagner (Units 3 and 4) for reliability purposes, subject to their specific operational restrictions. As proposed by Talen in its

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[28] As well as energy efficiency and demand response resources.

[29] RMR units are modeled in reliability studies and reserve calculations.

[30] Based on conversations with PJM and the IMM at the Deactivation Enhancements Senior Task Force November 9, 2023, meeting.

[31] The presence of the RMR units also impacts the computation of CETO and CETL, and thus has an indirect effect on the parameters influencing the auction outcome.

filings at FERC, the units will be offered into the energy market "with a status of 'unavailable in the Market' but will be available to be dispatched and scheduled by PJM".[32] However, Talen has stated that it does "not guarantee the availability of the Unit(s) in response to a PJM scheduling or dispatch notice."[33,34]

# 3. PJM'S CAPACITY MARKET

In the most recent PJM capacity auction, for the delivery year 2025/2026, the BGE LDA cleared at its maximum price of $466.35/MW-day. The rest of the RTO (with the exception of Dominion LDA) cleared at $269.92/MW-day, nine times higher than the RTO clearing price for 2024/2025. This section provides an overview of how the capacity market works, particularly around the capacity-constrained zones such as the BGE LDA. We also describe recent reforms to the market and the multiple ways they can affect market prices. Finally, we discuss the impact of the Brandon Shores and Wagner units no longer bidding into PJM's capacity market, even while continuing service under RMR arrangements.

## 3.1. Capacity Market Mechanisms

PJM's capacity market, known as the Reliability Pricing Model (or RPM), is the market-based mechanism that PJM uses to procure commitments from capacity resources to be available to meet future demand. The capacity market is meant to procure capacity at the lowest possible cost; it includes generation, storage, demand response, and energy efficiency resources. The quantity procured must meet system and local reliability standards, which PJM has historically defined as a loss of load expectation (LOLE) of no more than one day in ten years, or a 1-in-10 LOLE for the system, and a 1-in-25 LOLE for LDAs. In other words, to meet reliability standards, load should not exceed available capacity more than one day in 10 years. In the just completed base residual auction for the 25/26 delivery year (and for future auctions), PJM shifted its measure of resource adequacy risk to an expected unserved energy (EUE) metric,[35] which is

[32] FERC Docket No. ER24-1790-000, Brandon Shores Continuing Operates Rate Schedule (CORS) Transmittal Letter. April 18, 2024. Brandon Shores LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1790. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5176.

[33] FERC Docket No. ER24-1790-000, Brandon Shores Reliability Must Run Continuing Operations Rate Schedule, Attachment A. April 18, 2024. Brandon Shores LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1790. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5176.

[34] The units may also be offered based on their cost-based schedule into the Synchronized Reserve market when they are otherwise dispatched for reliability, and they will provide reactive power consistent with their capability and voltage schedules under their interconnection agreements. Any energy and ancillary service market revenues received by RMR units are netted out of the total RMR costs for cost recovery.

[35] "PJM proposes to assess its resource adequacy risk using the EUE metric, keyed to meeting the traditional one day in ten years LOLE metric that PJM has historically employed. PJM states that the current LOLE reliability criterion does not fully represent the three typical reliability dimensions: magnitude (MW), duration (hours), and frequency (numbers of events per time period). In contrast, PJM states that EUE provides a much more granular metric that allows the resource adequacy analysis to clearly differentiate among events of different duration and magnitude, and to better identify the scope of loss of load risk throughout the year. Further, PJM argues that the changing resource

still tied to meeting the one day in ten years (or 25 years) reliability metric. PJM expresses this reliability requirement as forecasted peak load plus a reserve margin. PJM conducts annual auctions to procure capacity and maintain reliability, starting with the Base Residual Auction (BRA) and subsequent incremental auctions. The capacity clearing price is the intercept point between the demand curve and the supply curve; the clearing price is paid to all cleared capacity resources for that delivery year.

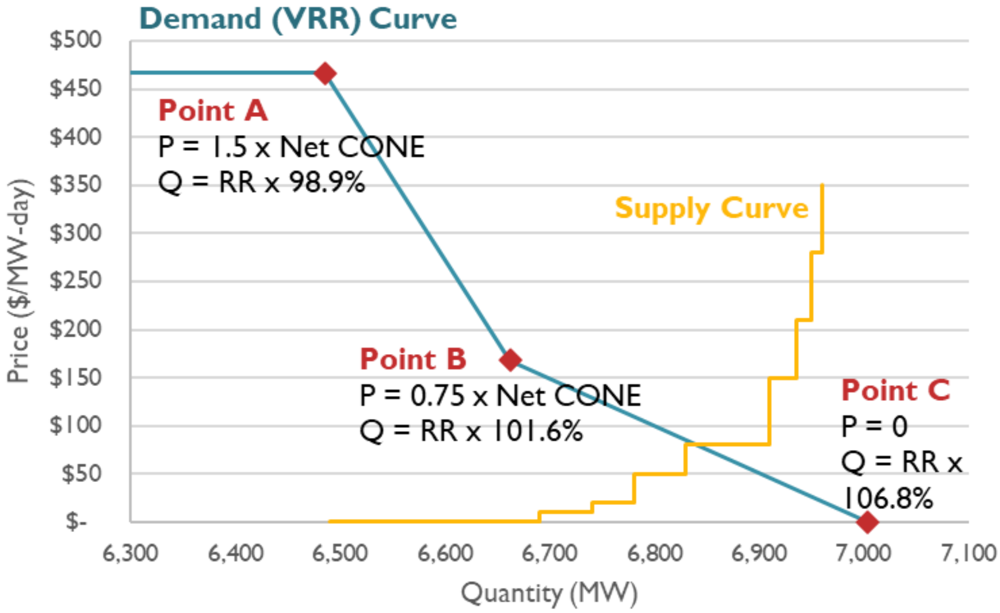
PJM uses a downward sloping demand curve, called the Variable Resource Requirement (VRR) curve, to specify prices and demand relative to the reserve margin requirements. To set the VRR curve, PJM conducts its annual Reserve Requirement Study. The study is a probabilistic risk modeling exercise that incorporates load forecasts, generation capabilities and outage rates, and other factors to determine the Installed Reserve Margin (IRM) necessary to meet the reliability standard (1-in-10 LOLE equivalency). Once approved by the PJM Board, the outputs of the study define the Reliability Requirement, which is used to determine the three points that make up the VRR Curve (points A, B, and C)[36] (Figure 1, with Pepco LDA as an example). The maximum price on the VRR curve is 1.5 times the net Cost of New Entry (CONE);[37] net CONE is the estimated price that a new generation resource would need to enter the market, net of energy market revenues.

mix, which increasingly will be composed of resources with greater hourly performance variability, further supports the need to include EUE in resource adequacy risk modeling." Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98, at 62.

[36] Each point on the VRR curve is defined by the reliability requirement and Net CONE (e.g. point B is set at 101.6% times the reliability requirement and 0.75 times Net CONE, and point C is set at 106.8% times the reliability requirement at a price of $0), creating a downward sloping curve. These values that define the curve are determined by PJM probabilistic modeling of reliability, and means that if capacity is more expensive, slightly less of it will be procured, while if capacity is less expensive, more capacity may be procured.

[37] Or Gross CONE, whichever is greatest.

Figure 1. Pepco's 2025/2026 VRR curve, where P is price ($/MW-day), Q is quantity (MW), and RR is reliability requirement, alongside an illustrative example supply curve (which does not reflect 2025/2026 supply offers and the resulting clearing price)




*Notes: the supply curve is for illustrative purposes only and is not based on real supply offers. VRR curve for Pepco LDA, 2025/2026 Planning Period Parameters for Base Residual Auction, April 12, 2024. Available at: https://www.pjm.com/markets-and-operations/rpm*

The MW of capacity a resource can offer into the market depends on its accreditation value, or its unforced capacity (UCAP). The UCAP is a measure of how much capacity a unit has at peak to contribute to system reliability. PJM has previously used a few capacity accreditation methods, specific to resource types.[38] But starting with the latest capacity auction (2025/2026), PJM shifted to a marginal Effective Load Carrying Capability approach (ELCC). ELCC accredits resources based on their marginal contribution to system resource adequacy across simulated scenarios.[39] Existing market participants are required to offer their UCAP at a price that reflects the costs they would avoid by not operating. This price is defined by Market Seller Offer Cap (MSOC) rules. New market participants can enter at a price of zero (price takers) or at prices that reflect their net costs of entering. Each supply offer (UCAP quantity and price) makes up the supply curve. The capacity price is set at the intercept point of the supply and demand curves.

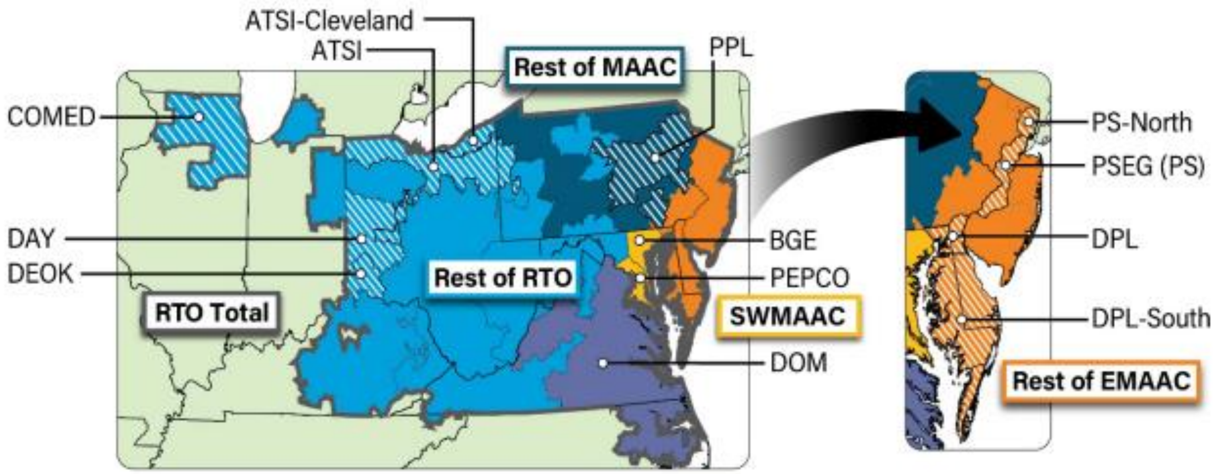
The capacity market clearing price produces a market signal for capacity resources; high prices indicate that supply is scare and encourages entry of new resources, while low prices indicate that there is more supply than the system needs for resource adequacy. The capacity market auction is designed to cost-effectively procure capacity to meet reliability requirements for both the entire RTO region as well as LDAs.

[38] Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98, at 3-5.

[39] Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98.

LDAs are subregions within PJM that are transmission-constrained and thus have limited import capability; LDAs are modeled in the capacity market separately from the rest of the unconstrained RTO. For purposes of the capacity market auctions, each modeled LDA will have its own reliability requirement and Net CONE value, and if certain criteria are met, its own VRR curve.[40] Figure 2 shows the modeled LDAs alongside the unconstrained RTO ("rest of RTO"), as of 2025/2026.

Figure 2. PJM's modeled LDAs

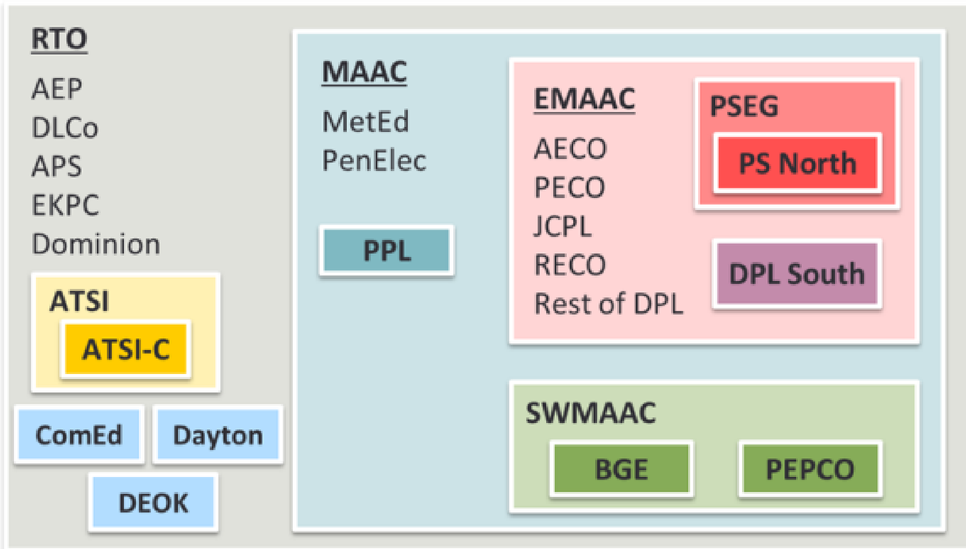



*Source: PJM Interconnection, LLC. 2025/2026 Base Residual Auction Report. July 30, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx*

PJM uses a nested model for determining the capacity market price, where a smaller LDA or a "child" LDA can procure capacity from its own local supply or from a larger "parent" LDA. Each LDA must meet its own local reliability requirement but is able to import capacity to satisfy that requirement up to the import limit that the transmission system can support (or the Capacity Emergency Transfer Limit (CETL)). Figure 3 shows the nested nature of modeled LDAs within PJM. Figure 2, above, also shows the nested structure, where darker colors are a child LDA (e.g., ATSI-C, in dark yellow, is a child of ATSI, in light yellow), and the parent-child relationship is indicated with an arrow.

[40] PJM Interconnection. 2024/2025 RPM Base Residual Auction Planning Period Parameters. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-planning-period-parameters-for-base-residual-auction-pdf.ashx.

Figure 3. Structure of nested parent and child LDAs in PJM

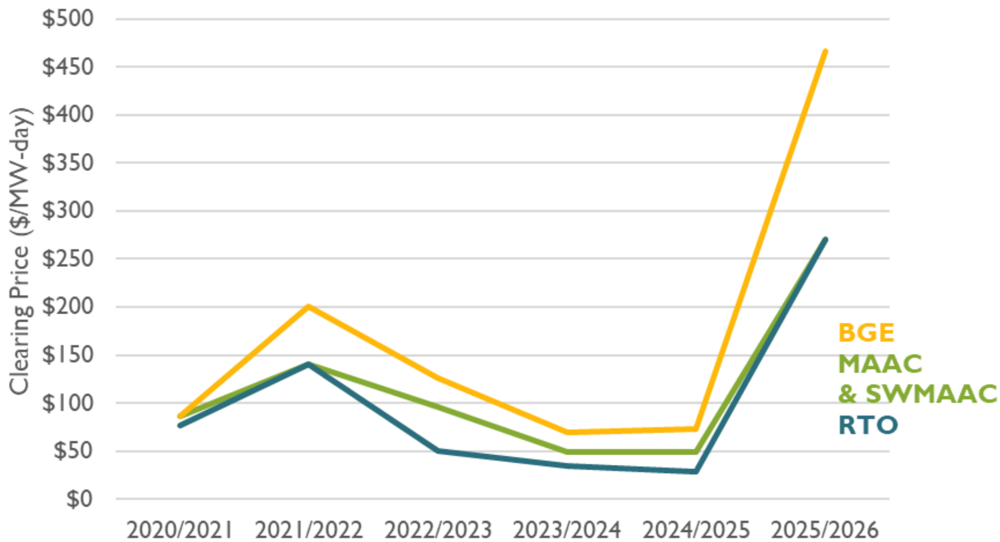



*Notes: Each rectangle and bold label represents modeled LDAs while individual energy zones listed in non-bold without boxes are not currently modeled. For example, BGE is the child LDA to SWMAAC, which in turn is a child LDA to MAAC. Source: Modeled LDAs for the 2022/2023 BRA. Newell A., Oates, D., Pfeifenberger, J., Spees, K., Hagerty, J.M., Pedtke, J., Witkin, M., Shorin, E. April 2018. Fourth Review of PJM's Variable Resource Requirement Curve. Prepared for PJM by The Brattle Group. Available at: https://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx.*

PJM's capacity market clearing mechanism is meant to find the lowest-cost solution to meet reliability standards in all LDAs, by optimizing local capacity availability and imports from parent LDAs. When an LDA is import-constrained, it can experience price separation from its parent LDA(s). Within the nested structure of the market, a clearing price in a child LDA is never lower than its parent LDA's clearing price.[41] If a child LDA does not have sufficient local capacity to meet its local peak, and transmission constraints prevent the LDA from importing enough capacity to make up the difference, a higher-cost resource might set the price for the child LDA at a higher clearing price than its parent LDA. In other words, instead of the child LDA clearing with its parent LDA at the parent LDA clearing price, it clears at a higher price. This has occurred in recent years in BGE LDA, relative to its parent LDA, SWMAAC. BGE LDA separated and experienced a higher price than its parent LDA over the last six auctions. On the other hand, the Pepco LDA, which is also part of SWMAAC, did not experience price separation. SWMAAC LDA itself cleared with its own parent, MAAC LDA, or the RTO as a whole (Figure 4).

[41] Newell A., Oates, D., Pfeifenberger, J., Spees, K., Hagerty, J.M., Pedtke, J., Witkin, M., Shorin, E. April 2018. Fourth Review of PJM's Variable Resource Requirement Curve. Prepared for PJM by The Brattle Group. Available at: https://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx

Figure 4. Clearing prices for BGE, MAAC and SWMAAC, and RTO from 2020/2021 to 2025/2026




*Source: Clearing prices in nominal dollars from RPM Base Residual Auction Results 2020/2021, 2021/2022, 2022/2023, 2023/2024, 2024/2025, and 2025/2026. PJM Interconnection LLC. Available at: https://www.pjm.com/markets-and-operations/rpm.*

As further discussed in Section 3.3 below, the conversion of the Brandon Shores and Wagner plants to RMR service was the major driver in the very high prices for the BGE LDA in the 2025/2026 delivery year, and possibly contributed to higher capacity prices seen across the RTO as whole.

## 3.2. Recent Capacity Market Reforms in PJM

On January 30, 2024, FERC approved major reforms to PJM's capacity market, which were implemented in the most recent BRA (2025/2026) which occurred in July 2024.[42] Although these changes are wide-ranging and impact many components of the market, the three main reforms relevant here are: (1) replacement of the current accreditation approach with a marginal ELCC accreditation approach for all generation capacity resources, (2) enhancement of PJM's resource adequacy risk modeling to evaluate risk on a more granular, hourly level, and (3) adjustments to how Net CONE is calculated.

### Market Reform Impact on UCAP

Capacity accreditation is the process of determining a given resource's UCAP, or the amount of capacity a resource can provide after accounting for factors like forced outages and intermittency. Starting in the delivery year 2025/2026 (and implemented with the just completed auction for that delivery year), PJM shifts to a marginal ELCC approach for capacity accreditation, which accredits these resources based on their marginal contribution to system resource adequacy across a number of simulated scenarios (given the anticipated resource mix). PJM's new accreditation

[42] Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket No. ER24-98.

methodology will reduce most generators' UCAP, with some generators affected more than others (each unit has its own accreditation rating). Table 5 shows the class ratings by resource type for the 2025/2026 BRA, under the historical capacity accreditation approach and the new marginal ELCC approach (expressed as a share of total nameplate capacity).

Table 5. PJM's average ELCC class ratings for the 2025/2026 BRA, using historical and marginal ELCC capacity accreditation

| Resource Type | 2025/2026 Class Rating (Historical Method) | 2025/2026 Class Rating (Marginal ELCC method) |
|---|---|---|
| Fixed-Tilt Solar | 30% | 9% |
| Tracking Solar | 50% | 14% |
| Coal | 87% | 84% |
| Gas Combined Cycle | 96% | 79% |
| Gas Combustion Turbine | 90% | 62% |
| Diesel (Oil) | 91% | 92% |

*Source: Class ratings for 2025/2026 using historical capacity accreditation method from: PJM Interconnection, December 1, 2023. Docket ER24-99-001. Responses to Deficiency Letter – Capacity Market Reforms to Accommodate the Energy Transition, at 27. Updated 2025/2026 Class Ratings from: PJM Interconnection, ELCC Class Ratings for the 2025/2026 Base Residual Auction, March 13, 2024. Available at: https://www2.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx.*

The updated capacity accreditation will reduce the total supply of UCAP, with some LDAs affected more than others. The accreditation methodology impacts natural gas plants and solar generators the most. Therefore, LDAs with a large quantity of solar and gas see the largest decrease in their UCAP supply. For example, in the 2024/2025 BRA, natural gas resources made up 81 percent of cleared UCAP in Pepco LDA, but only 13 percent of cleared UCAP capacity in BGE LDA.[43] However, together these two LDAs make up SWMAAC; gas plants represented over 40 percent of cleared UCAP in SWMAAC in the 2024/2025 auction.[44] As a result, the BGE LDA may not see a major difference in supplied UCAP due to the ELCC adjustments (barring additional retirements), while SWMAAC may see a much larger impact on its available UCAP as a result of PJM's new capacity accreditation approach.[45]

## Market Reform Impact on Offer Price

Changes in supplied UCAP in turn affect units' offer prices. If a unit's UCAP decreases under the new accreditation approach, its fixed unit costs will not—it still needs to recover the same total dollar amount for the equivalent offer under the new accreditation. For instance, consider an 8 MW UCAP resource that previously bid in at $50/MW-day, reflecting costs of $400/day; if now accredited at 5 MW UCAP, the offer would be adjusted to $80/MW-day resulting in the

[43] Calvert Cliffs is physically located in BGE LDA but is modeled in its parent LDA, SWMAAC LDA. Calvert Cliffs is included in the percentage calculation for SWMAAC LDA but not BGE LDA. Monitoring Analytics. October 30, 2023. Analysis of the 2024/2025 RPM Base Residual Auction. The Independent Market Monitor for PJM. Available at: https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf.

[44] Ibid.

[45] Offered and cleared MW by resource type is available in the IMM's Analysis of the RPM Base Residual Auction, which will be available for the 2025/2026 delivery year in a few months.

same total $400/day amount.[46] Although the magnitude of change depends on the specifics of each LDA, moving to a marginal ELCC capacity accreditation approach ultimately results in a shift in supply curves up and to the left (i.e., up in price and down in quantity) relative to the supply curves seen under the former capacity construct.[47]

### Market Reform Impact on VRR Demand Curve

The VRR demand curve also shifts up and to the left (once again, up in price and down in quantity) in the 2025/2026 capacity market auction. This shift occurs for several reasons. PJM has adopted hourly probabilistic modeling for its Reserve Requirement Study, which ultimately defines the reliability requirements and the VRR curve. PJM states that this change, along with enhanced risk modeling, will improve the accuracy and confidence in the Installed Reserve Margin and Reliability Requirement. In effect, the accredited (UCAP) capacity required for the RTO as a whole, as well as every child LDA, decreases. Since each megawatt of nameplate capacity (ICAP) is being accredited in a more rigorous and accurate manner, each megawatt of firm capacity (UCAP) is worth more. Therefore, PJM will need to procure less firm capacity to meet reliability requirements. For example, the reliability requirement for the 2025/2026 capacity auction decreased by 8 percent for the BGE LDA relative to the 2024/2025 delivery year.[48]

Importantly, reducing the reliability requirement shifts the VRR curve to the left (down in quantity), as the VRR curve of each LDA is based on its reliability requirement. The VRR price points also increase, as Net CONE will be tied to the ELCC of the reference resource, rather than a pool-wide average forced outage rate. [49] Specifically, Net CONE is converted to $/MW-day (UCAP) using the ELCC class rating of the Reference Resource, rather than using the pool-wide average effective forced outage rate (EFORd). This conversion results in a higher Net CONE.[50] The higher Net CONE is important because the maximum capacity market clearing price under PJM rules is 1.5 times the Net CONE value.  These changes to the VRR curve were implemented in the 2025/2026 capacity auction.[51]

Finally, PJM has changed how it models reliability import requirements. PJM will adopt hourly probabilistic modeling to model the Capacity Emergency Transfer Objective (CETO). CETO is the required transfer amount to satisfy an LDA's reliability requirements. This change could impact which LDAs are considered constrained and must be modeled separately from the rest of the RTO.

[46] PJM Market Implementation Committee. January 10, 2024. Informational Posting: Simulation Analysis of PJM CIFP-RA Filing. Available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2024/20240110/20240110-informational-only---simulation-analysis-of-pjm-cifp-ra-filing.ashx

[47] Ibid.

[48] Planning Period Parameters for Base Residual Auction. Available at: https://www.pjm.com/markets-and-operations/rpm.

[49] Based on pool-wide average EFORd (effective forced outage) rate.

[50] The ELCC of the reference resource is used to convert Net CONE ICAP to UCAP. PJM Market Implementation Committee. January 10, 2024. Informational Posting: Simulation Analysis of PJM CIFP-RA Filing. Available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2024/20240110/20240110-informational-only---simulation-analysis-of-pjm-cifp-ra-filing.ashx.

[51] Planning Period Parameters for Base Residual Auction, April 12, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction.ashx.

## 3.3. 2025/2026 Delivery Year Capacity Market Results

### Impact of Brandon Shores and Wagner Retirements on BGE LDA's Capacity Price

In the capacity market auction, the capacity price is set at the point where the demand curve and the supply curve intercept. The supply of capacity of any given LDA is made up of three resource types: (1) generation capacity, (2) demand response, and if constrained, then (3) capacity imports.[52] When there are reductions in supply (for example, if a plant retires in a highly constrained zone), the supply curve shifts left. This moves the intercept point with the VRR curve upwards and pushes the capacity price higher. If there is not enough supply (generating capacity, demand response, and imported capacity) for the supply curve to intercept the demand curve, then the capacity price for that LDA will be set at the maximum, 1.5 times Net CONE. In other words, to avoid maximum price, the supply curve has to intercept the demand curve to the right and downward of Point A (the maximum price point on the VRR curve), as displayed in Figure 1 (above).

The BGE LDA has been capacity-constrained in recent years; the BGE LDA's capacity prices were about twice that of the RTO price for the last four years (as presented in Figure 4, above). From 2022/2023 to 2024/2025, only a third of the BGE LDA's cleared capacity came from local resources located within the LDA, the remainder was imported from its parent LDA (SWMAAC).[53] In the latest auction, for 2025/2026, less than 10 percent of the BGE LDA's cleared capacity was from local resources.[54] In 2024/2025, Brandon Shores and Wagner represent roughly 75 percent of generation capacity in BGE LDA,[55] and together they were responsible for over 60 percent of all cleared capacity (inclusive of supply-side generators, demand response, and energy efficiency). With Brandon Shores and Wagner removed from the supply stack, the BGE LDA does not have enough capacity to intercept the demand curve to the right of Point A on its VRR curve. There is not enough capacity to exceed Point A's UCAP Level, and as a result, the BGE LDA clearing price is at its maximum, $466.35/MW-day. This 2025/2026 maximum price is over six times the BGE LDA's clearing price in the 2024/2025 BRA ($73/MW-day); it will begin to affect customers' electric bills in the BGE LDA in June 2025 or soon after (as discussed in Section 4).

Concerningly, not only is the BGE LDA experiencing a record high capacity price in 2025/2026, but there is not enough capacity to meet the BGE LDA's reliability requirement. PJM's reliability requirement is the target level of capacity resources to meet PJM's reliability standards, i.e., a loss of load expectation of no more than one day in 25 years for LDAs (now expressed as an EUE metric). Specifically, the BGE LDA's remaining internal resources, the maximum amount of

[52] Cleared resources have historically also included energy efficiency. However, energy efficiency is not included in the clearing mechanism and therefore cannot set the price; it is added to cleared resources after the clearing price has been established. Monitoring Analytics, LLC. April 3, 2024. EE Addback Education. Available at: https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_EE_Addback_Education_20240403.pdf.

[53] Based on data from PJM's RPM Base Residual Auction Results and the IMM's Analysis of the RPM Base Residual Auction, for 2022/2023, 2023/2024, and 2024/2025. Available at: https://www.pjm.com/markets-and-operations/rpm.aspx and https://www.monitoringanalytics.com/reports/Reports/2023.shtml.

[54] 2025/2026 Base Residual Auction Results, July 31, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-results.ashx

[55] We assigned class capacity accreditation values to Brandon Shores units 1 and 2, and Wagner units 1, 3, 4 and CT. Total UCAP based on all offered UCAP from the 2024/2025 BRA, from Monitoring Analytics, October 2023. Analysis of the 2024/2025 RPM Base Residual Auction. Available at: https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf

capacity that can be imported on the existing transmission system, and the cleared price responsive demand totals 6,765 MW, which is 176 MW below the LDA's reliability requirement of 6,941 MW. BGE LDA's capacity shortfall relative to its reliability requirement suggests that the probability of a loss of load event in the LDA is higher than PJM's reliability standard, further impacting electric customers in that zone.

Beyond the 2025/2026 delivery year, the very high prices may incentivize more demand response resources to bid into the market, which could reduce the clearing price if there is enough demand response to exceed the minimum required UCAP. Similarly, the high prices are in theory meant to incentivize new generation in the LDA. However, as discussed in Section 5, the years-long interconnection queue delays in PJM will likely prevent a large amount of resources from interconnecting in the BGE LDA any time soon. Without major changes to transmission import capacity or generation capacity, prices are likely going to remain at very elevated levels (even if not at the maximum of 1.5 times Net CONE, Point A). High prices are especially likely for PJM's next capacity auction (for the 2026/2027 delivery year) because it will occur in December 2024—less than five months following the BRA for 2025/2026 and only 1 ½ years before the beginning of the delivery year for that next auction. Likewise, the possibility of reliability issues in the BGE LDA as a result of the capacity shortfall will likely be an ongoing concern until more capacity becomes available and the reliability requirements are achieved, via new generation, demand response, or upgraded transmission capacity.

### RTO and other LDA Capacity Market Prices in 2025/2026

In PJM's BRA for the 2025/2026 delivery year, which was finalized in July 2024, capacity market prices increased substantially in 2025/2026 from the previous delivery year. Specifically, the RTO price increased by over 800 percent, while the price for BGE LDA increased by over 500 percent (Table 7). In 2025/2026, only BGE and DOM LDAs experienced price separation, and both cleared at their maximum. These RTO and LDA prices are record highs, never before seen in PJM.  The total RTO-wide cost to electric customers increased from $2.2 billion in 2024/2025 to $14.7 billion in 2025/2026.[56]

[56] 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

Table 6. BRA clearing prices for 2024/2025 and 2025/2026 delivery years, by LDA, with bolded prices showing price separation

| LDA | 2024/2025 Clearing Price ($/MW-day) | 2025/2026 Clearing Price ($/MW-day) |
|---|---|---|
| RTO | $28.92 | $269.92 |
| MAAC | **$49.49** | $269.92 |
| EMAAC | **$54.95** | $269.92 |
| SWMAAC | **$49.49** | $269.92 |
| PS | **$54.95** | $269.92 |
| PSNORTH | **$54.95** | $269.92 |
| DPLSOUTH | **$426.17** | $269.92 |
| PEPCO | **$49.49** | $269.92 |
| ATSI | $28.92 | $269.92 |
| ATSI-CLEVELAND | $28.92 | $269.92 |
| COMED | $28.92 | $269.92 |
| BGE | **$73.00** | **$466.35** |
| PL | **$49.49** | $269.92 |
| DAYTON | $28.92 | $269.92 |
| DEOK | **$96.24** | $269.92 |
| DOM | $28.92 | **$444.26** |

*Notes: DPL-South 2024/2025 clearing price was originally $90.64/MW-day. It was repriced due to a Third Circuit Court of Appeals reversal of PJM's determination of the original price. The updated $426.17/MW-day clearing price for DPL-South is now approved by FERC, but still the subject of litigation. PJM's RPM Base Residual Auction Results for 2024/2025 and 2025/2026, available at: https://www.pjm.com/markets-and-operations/rpm*

PJM points to three key factors driving these unprecedented price spikes:[57]

- Load: forecasted peak load increased by 3,243 MW (e.g. from new data centers).
- Retirements: actual retirements across the PJM footprint, RMR units participating as energy-only resources (i.e., Brandon Shores, Wagner and Indian River), and must-offer exceptions for units preparing to retire.
- Reductions in UCAP supply due to the new capacity accreditation methods: as discussed in 3.2, updated ELCC ratings have reduced the total amount of supply, in UCAP terms.

The capacity shortfall in BGE LDA from the conversion of Brandon Shores and Wagner to RMR service likely had spillover effects into the RTO as a whole, increasing the RTO-wide clearing price and impacting electric customers in PJM beyond those in the BGE LDA. We conducted a counterfactual analysis of clearing prices in PJM, and found that if Brandon Shores and Wagner RMR units had remained as supply-side resources in the capacity market, the RTO as a whole

[57] 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

would have cleared at $163.46/MW-day. This scenario would have shifted the supply curve to the right and moved the demand and supply curve intercept point down and right, resulting in a lower clearing price. In this scenario, BGE, SWMAAC, and MAAC LDAs would not have separated from the RTO. This analysis is based on three assumptions. First, we assume that Brandon Shores (units 1 and 2) and Wagner (units 3 and 4) had offer prices at or below $163.46/MW-day, which is more than double their offer price in 2024/2025.[58] Second, we assume that the resources that were required to meet the RTO reliability requirement and subsequently cleared had offer prices at or below $163.46/MW-day. In other words, we assume that Brandon Shores and Wagner were marginal resources or were towards the top of the stack of cleared resources. Third, with the exception of the Dominion LDA, we assume that other LDAs would not have separated from the RTO and caused other cascading price impacts on the RTO or the MAAC LDA. Given these assumptions, this counterfactual represents the lower bound of clearing prices for the 2025/2026 base residual auction with Brandon Shores and Wagner participating. If the RTO cleared at $163.46/MW-day for the 2025/2026 BRA, electric customers across the RTO would save over $5 billion in that delivery year. Stated otherwise, our counterfactual analysis demonstrates that the removal of 2,000 MW (ELCC adjusted about 1,600 MW) from the resources clearing the auction—the equivalent of less than 1.5 percent of the 135,000 MW that cleared the auction—had a region-wide impact that will benefit generators (and cost customers) over $5 billion.

Under the same assumptions, we also considered the outcome of the RMR and 2025/2026 capacity auction on Talen's bottom line by comparing Talen's expected revenues from the outcome of the auction to our counterfactual. We found that Talen's revenues for the 2025-2026 delivery year increased by $360 million compared to what its revenues would have been had the Talen RMR units participated in the capacity market.[59]

# 4. CUSTOMER BILL AND RATE IMPACTS OF RMRS IN MARYLAND

Across the PJM footprint, electric utility customers will see rising costs as a result of the increased capacity clearing prices for the 2025/2026 delivery year. For customers in the BGE LDA, the impact of the soaring capacity price is compounded by having to pay for a substantial portion of the out-of-market RMR arrangement costs for Brandon Shores and Wagner. This section describes those impacts for electric utility customers in the BGE LDA, as well as the impacts to customers in other LDAs within Maryland.

## 4.1. Analytical Approach and Assumptions

Using utility data and billing determinants from the U.S. Energy Information Administration (EIA),[60] we examined the bill and rate impact associated with RMR costs and recent capacity

[58] The capacity price in the BGE LDA in 2024/2025 was $73/MW-day, and most if not all of Brandon Shores and Wagner cleared as capacity resources in that delivery year.

[59] The $360 million benefit includes Talen's revenue from the RMR arrangement, where Brandon Shores and Wagner capacity market revenue would be netted out from final RMR costs.

[60] Billing determinants from U.S. Energy Information Administration form 861.

market results for all four Maryland LDAs: BGE, Pepco, DPL-South, and APS.[61] We focused specifically on Maryland's share of each LDA, rather than the LDAs as a whole. BGE's Maryland share is the same as its entire LDA because the BGE LDA is located entirely within Maryland. Because EIA billing determinant data was only available up to 2022, we assumed that energy, transmission, distribution, and other costs have remained unchanged since 2022 and will continue to be stable through the end of the study period. Capacity market costs for the 2025/2026 delivery year are compared against capacity market results from 2024/2025. This rate and bill impact analysis does not include the cost of the transmission solutions approved for the BGE LDA and the surrounding areas that aim to address the reliability impact associated with Brandon Shores' and Wagner's retirement.

### Capacity Market Costs Paid by Customers

When an LDA is constrained, such as the BGE LDA, Capacity Transfer Rights (CTRs) are allocated to loads within that LDA. CTRs essentially represent the value of the transmission system's ability to "transfer" capacity resources to the LDA zone and offset "capacity congestion" effects. These are rights for load (i.e. customers) to receive payments that offset, in whole or in part, the charges attributable to the locational price adder. The locational price adder is the component of the clearing price that represents the price-separated clearing price relative to its parent LDA clearing price. The CTRs are payments equal to the locational price adder times the load's pro rata share of the lower-priced capacity imported into the LDA.[62] CTRs serve to offset a portion of the higher capacity prices for customers in that constrained LDA. We used the CTR allocation and annual capacity market costs for customers provided in PJM's 2025/2026 Base Residual Auction Results (Excel workbook).[63]

### Timing of Bill and Rate Impacts

The rate and bill impacts will be felt starting in mid-2025 and beyond, and different customers could feel the impacts at different times. For retail customers taking standard offer service, electric utilities procure energy and capacity from wholesale suppliers through a competitive bidding process that occurs twice a year.[64] These wholesale suppliers are the entities that directly pay for increased capacity costs; their bid price in the competitive bidding process reflects capacity market costs. The winning wholesale supplier of that bidding process then supplies electricity to the utilities at an agreed-upon rate, for six months, who then pass on those costs to their customers. Standard offer service power procurement uses a proxy price for capacity costs because of the delays in running PJM capacity auctions. The proxy price will be adjusted based on the actual capacity market results. This adjustment will raise the wholesale supply contract prices for service starting June 1, 2025, and standard offer service customers will see the impact in the bills starting on that date. Electric customers may choose to procure their own electricity supply from alternative electricity suppliers, who also work with wholesale

[61] This analysis does not account for the transmission solutions approved for Maryland and the surrounding areas, in response to Brandon Shore's planned retirement.

[62] Allocation of CTR MWs to LSEs, April 7, 2021. Available at: https://www2.pjm.com/-/media/committees-groups/committees/mic/2021/20210407/20210407-item-05a-rpm-capacity-transfer-rights-pjm-education.ashx

[63] 2025/2026 Base Residual Auction Results, July 31, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-results.ashx

[64] Residential and small commercial customers standard offer service bids occur twice a year, and large commercial bids occur quarterly. Maryland Public Service Commission. Standard Offer Service. Available at: https://www.psc.state.md.us/electricity/standard-offer-service/

suppliers to procure energy and capacity. The impact of higher capacity prices on those customers will depend on the terms of the retail supply contract.

## 4.2. RMR Costs and Capacity Market Impacts for Customers in BGE LDA

Talen Energy filed initial fixed RMR costs for Brandon Shores and Wagner that together total $215.7 million per year. Although these RMR arrangement costs are expected to be litigated at FERC, we expect that BGE LDA customers will bear 74 percent of these RMR costs. As a result, BGE LDA customers could see their bills increase by 5 percent, resulting in an average residential bill increase of $5 per month. Commercial customers[65] could see their bills increase by $54 per month (Table 7). These RMR costs are expected to last until at least December 2028, when PJM currently plans to have the transmission solutions in place. The RMR arrangements could be extended if these transmission projects are delayed or if the region continues to face reliability issues beyond 2028, which would mean continued rate and bill impacts for BGE LDA electric customers.

Second, Brandon Shores' and Wagner's removal from the capacity market has significantly impacted the BGE LDA clearing price. Those impacts will, in turn, be passed on to electric customers in that zone. Specifically, we expect the capacity price spike to increase bills by 14 percent In the BGE LDA[66]—in addition to the 5 percent from RMR arrangement costs (Table 7). From the capacity price increase alone, average residential and commercial customers could see their bills increase by $16 per month and $170 per month, respectively (excluding RMR costs).

When considering both the capacity market impact and the RMR service arrangement costs together, total bills are likely to increase by 19 percent—an extra $21 on the average residential customer bill and $224 on the average commercial monthly bill (Table 7). Over the course of a year, that could result in residential electric customers paying an additional $247 annually, and commercial customers paying $2,685 of additional costs. Customers will likely feel these costs impacts until at least December 2028, when PJM has planned for the transmission solutions to be in place (but the timeline for transmission solution completion is highly uncertain). Once the transmission projects are complete (assuming no other reliability issues), the RMRs will no longer be needed for reliability, and the BGE LDA will be able to mitigate high capacity prices by importing lower-priced capacity from neighboring LDAs. In addition, before 2028, additional demand response or generating resources may offer into the market, partially mitigating capacity price increases in the BGE LDA. However, given that the next auction (for 2026/2027) is less than five months from the latest auction (2025/2026) and the beginning of that auction's delivery year is only 1 ½ years following its completion, it is unlikely that there will be any change to BGE LDA capacity price until at least 2027/2028.

[65] Industrial customers are excluded from this analysis, due to the wide variation in energy use and monthly bills.

[66] Capacity costs are only a small portion of a customer's electric bill.

Table 7. Bill and Rate Impacts for BGE LDA of the Brandon Shores and Wagner RMRs (capacity market impacts and RMR cost impacts)

| Cost Category | Monthly Bill Change (%) | Additional Costs on Monthly Bills ($) | |
|---|---|---|---|
| | All | Residential | Commercial |
| **Total Cost** | **19%** | **$21** | **$224** |
| *Capacity Market Impact* | *14%* | *$16* | *$170* |
| *RMR Costs* | *5%* | *$5* | *$54* |

*Source: See description in text. Due to the wide variability in industrial customer types, they were not included in this rate impact analysis.*

### 4.3. Costs Impacts for Maryland Customers in Pepco, DPL-South, and APS LDAs

Capacity market prices for the 2025/2026 delivery year in PJM have surged, with the RTO experiencing a nine-fold increase in clearing prices compared to the previous BRA. These unprecedented costs will ultimately be passed onto customers, with major impacts felt in Maryland. Specifically, Maryland customers in APS, DPL-South, and Pepco zones could see their monthly bills increasing by 24 percent, 2 percent, and 11 percent, respectively (Table 8). On average, this translates into a monthly increase of $18, $4, and $14 for the average residential customer in APS, DPL-South, and Pepco zones, respectively (Table 8).

These bill impacts represent the incremental change from the 2024/2025 to 2025/2026 delivery years. APS LDA generally clears with the RTO, meaning that in the previous auction the clearing price was $29/MW-day, while Pepco LDA cleared with MAAC at $49/MW-day. In the 2024/2025 BRA, DPL-South LDA separated at $426/MW-day,[67] but cleared with the RTO in the 2025/2026 BRA at $270/MW-day. The fact that the APS LDA historically has cleared at the lowest price—and has benefitted from the lowest past capacity prices—helps explain why the APS LDA has the largest bill impact relative to the other Maryland LDAs, including BGE's LDA. In addition, CTRs are used to help mitigate the customer impact of higher-priced capacity in constrained LDAs (e.g. BGE's), which also helps to explain why the BGE bill impact is not magnitudes higher than that of the APS and Pepco LDAs, despite the extreme capacity clearing price in the BGE LDA. CTRs also insulated electric customers from the high clearing prices in DPL-South LDA in 2024/2025, which results in only a small bill increase for DPL-South LDA customers between 2024/2025 and 2025/2026.

We also assessed the bill impact of the RMR costs for the Maryland portion of the Pepco, DPL-South, and APS LDAs, using the same methods described above. We find that residential electric customers in the Maryland portion of the Pepco LDA will experience a small increase (roughly $1 per month) in their bills from Brandon Shores and Wagner RMR costs, starting in June 2025 (Table 8). The Maryland portion of the APS and DPL-South LDAs will pay for 0.1 and 1 percent of the Brandon Shores and Wagner RMR costs, respectively, and thus residential customers will not see any noticeable impact on their bills as a result of these RMRs (Table 8).

[67] DPL-South 2024/2025 clearing price was originally $90.64/MW-day. It was repriced due to a Third Circuit Court of Appeals reversal of PJM's determination of the original price. The updated $426.17/MW-day clearing price for DPL-South is now approved by FERC, but still the subject of litigation.

Table 8. Bill and Rate Impacts for the Maryland portion of APS, DPL-South, and Pepco LDAs, of the 2025/2026 capacity market and the RMR costs for Brandon Shores and Wagner

| Maryland LDAs | Cost Category | Monthly Bill Change (%) | Additional Costs on Monthly Bills ($) | |
|---|---|---|---|---|
| | | All | Residential | Commercial |
| APS LDA Customers (Maryland only) | **Total Cost** | **24%** | **$18** | **$81** |
| | *Capacity Price* | *24%* | *$18* | *$81* |
| | *RMR Cost* | *< 1%* | *< $1* | *< $1* |
| DPL-South LDA Customers (Maryland only) | **Total Cost** | **2%** | **$4** | **$18** |
| | *Capacity Price* | *2%* | *$4* | *$16* |
| | *RMR Cost* | *< 1%* | *< $1* | *$2* |
| Pepco LDA Customers (Maryland only) | **Total Cost** | **11%** | **$15** | **$172** |
| | *Capacity Price* | *10%* | *$14* | *$163* |
| | *RMR Cost* | *1%* | *$1* | *$9* |

*Source: See description in text. Due to the wide variability in industrial customer types, they were not included in this rate impact analysis*

## 5. LOOKING FORWARD BEYOND THE 2025/2026 DELIVERY YEAR

For the BGE LDA, PJM suggests that the reliability issues and transmission constraints associated with Brandon Shores and Wagner will be mitigated by the end of 2028 once transmission solutions are in place. That outcome is by no means a certainty. Project delays related to these factors may very well mean the BGE LDA could face reliability constraints after 2028, thus incurring even more costs for customers. In addition, PJM has been struggling with a massive backlog of new project interconnections, while at the same time working towards compliance with new and anticipated FERC reforms. These factors complicate the development of new generation within the BGE LDA and throughout PJM, which would help alleviate the very high capacity prices seen in the latest auction for the BGE LDA and across the RTO. Unfortunately, we are unlikely to see any major relief by 2026/2027, as that delivery year's capacity auction is scheduled for December 2024, less than five months after the completion of the July 2024 auction for 2025/2026 and only 1 ½ years before the beginning of the delivery year for that auction (leaving a very tight timeline for constructing a new plant).

According to PJM, if there are no delays, it will take a customer in the interconnection queue about 10 months from queue entry for an impact study to be tendered. The full timeline from queue entry to final agreement is between 2.25 and 2.54 years as reported by PJM.[68] However, that timeline has not been accurate for at least the past few years.

[68] PJM Learning Center, "Connecting to the Grid FAQs." Available at: https://learn.pjm.com/three-priorities/planning-for-the-future/connecting-grid/how-long-does-the-interconnection-process-take

In 2020, PJM initiated a stakeholder process to explore interconnection reforms that ultimately led to a pause or closure of the queue in 2022 to allow PJM to address backlogs and implement reforms. PJM determined that it would not review new projects until the fourth quarter of 2025—meaning final decisions on those projects could come as late as 2027.[69]

PJM's reforms include a move from a serial first-come, first-served process of reviewing interconnection requests to a first-ready, first-served cluster study process. The cluster study process would enable PJM to study more projects in a shorter amount of time. Addressing ready projects first also reduces the risk of speculative projects withdrawing from the interconnection queue. As many as 33 percent of projects were withdrawing from the queue after initial feasibility studies, and project withdrawals impact other projects as they often trigger re-studies for other resources.[70] FERC approved PJM's proposed reforms in November 2022.[71] Under PJM's original plans, the transition period to clear the existing backlog began in July 2023 and is intended to be complete by 2026, after which PJM could begin processing all requests submitted after October 2021.[72]

Then in late July 2023, FERC announced Order 2023. This order required RTOs, including PJM, to overhaul their interconnection processes. Order 2023 has raised questions about whether PJM's initial reforms and timelines for its regionally planned transition will be impacted, and if so, how. Order 2023 has some language about not interfering with in-progress cluster studies and transmission processes, but the Commission has also rejected any presumption of compliance for recently approved interconnection process reforms such as PJM's.[73] PJM has asked for a re-hearing and for clarification from FERC on Order 2023, as have other RTOs. On March 21, 2024, FERC issued Order 2023-A, which responds to those requests for re-hearing and clarification and requires incremental upgrades from the initial order. As PJM continues to litigate these questions, it has made progress implementing its reforms by kicking off the transition cycle of its reformed interconnection process on January 22, 2024.[74]

Currently, the BGE LDA has 13 interconnection requests in the PJM queue, equal to roughly 1,200 MW of capacity. Storage represents about 75 percent and solar makes up 25 percent of the 13 requests.[75] Some of these projects have been in the queue since 2020, and over half since 2021, yet they are still not interconnected. Although these 13 projects combined are roughly equal to the UCAP of Brandon Shores, based on historical queue conversion rates, it is extremely unlikely that they will all be constructed. However, as the current "fast-lane" transition cycle gets underway, PJM expects that projects sorted in this cycle will be complete in mid-2025. This means 46,000 MW of new generation across PJM could be cleared and moved to

[69] Bruggers, James. 2022. "Largest US grid operator puts 1,200 mostly solar projects on hold for 2 years." *Courier Journal*, April 30, 2022. https://www.courier-journal.com/story/news/local/science/environment/2022/04/30/solar-projects-put-pause-largest-us-power-grid-operator/9587074002/

[70] PJM Interconnection, L.L.C., Docket No. ER22-2110, Tariff Revisions for Interconnection Process Reform, Request for Commission Action by October 3, 2022, and Request for 30-Day Comment Period.

[71] PJM Inside Lines, "FERC Approves Interconnection Process Reform Plan." Available at: https://insidelines.pjm.com/ferc-approves-interconnection-process-reform-plan/

[72] PJM Inside Lines, "Transition to New Interconnection Process Begins July 10." Available at: https://insidelines.pjm.com/transition-to-new-interconnection-process-begins-july-10/

[73] PJM Request for Clarification and Rehearing of PJM Interconnection, 179 FERC ¶ 61,194 p. 8-10 (2023).

[74] PJM Inside Lines, "Transition Cycle 1 of New Interconnection Process Begins Jan. 22." Available at: https://insidelines.pjm.com/transition-cycle-1-of-new-interconnection-process-begins-jan-22/.

[75] PJM Services Request Status. Available at: https://www.pjm.com/planning/service-requests/services-request-status

construction starting in mid-2025,[76] some of which could mitigate high capacity prices in 2026/2027 and beyond, including in the BGE LDA (though given the short time period until the next BRA (December 2024) and the start of its delivery year (June 1, 2026), it is unlikely that there will be major changes to supply before then).

If the capacity market is well designed and is working efficiently, it should send a clear price signal and incentivize the building of more capacity in the BGE LDA. Nonetheless, the transmission solutions will not be in service until the end of 2028, roughly 3.5 years from the start of RMR arrangements for Brandon Shores and Wagner. Given the high uncertainty around queue waiting times, the current backlog, and interconnection reforms, it appears likely that wait times for new entrants to the queue could be longer than 3.5 years, if not more, so that their entry into the market will not help to address the anticipated RMRs and the related capacity market disruptions. This is far longer than the five months until the next capacity market auction, set to occur in December 2024. Without rapid and significant improvements to the interconnection process in PJM, reliability issues, RMRs, and high capacity prices could continue escalating costs for Marylanders for years to come.

[76] RTO Insider, "PJM Initiates Transitional Interconnection Queue." Available at: https://www.rtoinsider.com/69131-pjm-initiates-transitional-interconnection-queue/.