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Maryland Resource Adequacy FAQs

What is resource adequacy?

Resource adequacy requires having enough electricity generation to serve peak demand—including a "reserve margin" buffer for uncertainty—along with enough room on the transmission system to reliably deliver the power to customers. An assessment of resource adequacy depends on the geographic area, the transmission system's ability to deliver power to the area, and available generation.

Who is responsible for ensuring resource adequacy in Maryland?

PJM Interconnection, LLC (PJM), the regional transmission organization (RTO) for Maryland and 13 other jurisdictions in the region, is responsible for ensuring resource adequacy in Maryland. RTOs like PJM operate the transmission system and the wholesale energy markets and are regulated by the Federal Energy Regulatory Commission (FERC). Subject to FERC's oversight, PJM sets the reserve margin necessary to meet the reliability and resource adequacy criteria established by the North American Electric Reliability Corporation (NERC) and the regional entity to which NERC delegates authority, the Reliability First Corporation, to determine and assess electric reliability, including resource adequacy, for the PJM region.

PJM evaluates resource adequacy for the PJM region as a whole, as well as smaller zones within the region (called Locational Deliverability Areas or LDAs).

How is resource adequacy achieved in Maryland?

Achieving resource adequacy for an area of Maryland (such as central Maryland) depends on a combination of the transmission system's ability to transfer power into that area plus the generation located within the area. The combined transmission capability and generation within that area must be enough to meet the forecasted electric demand requirements for that area as determined by PJM. The transmission transfer capability into an area helps ensure reliability for that area and brings in lower cost resources from other parts of the region, which lowers prices for customers in the local area.

To procure the generation resources needed to maintain resource adequacy, PJM runs auctions for "capacity" in which generation companies commit to being available to run when needed to meet demand. The capacity auctions (in PJM parlance, the Base Residual Auction, or BRA) run annually and have the goal of ensuring sufficient generation to meet power needs for the entire PJM regional territory and—based on the ability of the transmission system to import power—for the smaller zones within the region. The auction is designed to enable the procurement of sufficient resources to satisfy the resource adequacy criteria applicable to PJM and Maryland.

What is the resource adequacy situation now?

Between the capacity market and other arrangements, there are sufficient generation and transmission facilities available to satisfy Maryland's resource adequacy needs. PJM ran an auction in July 2024 to secure capacity for the 2025/2026 delivery year—June 1, 2025, to May 31, 2026. That auction secured enough capacity to meet anticipated customer peak power demands and a sufficient reserve margin for the PJM region as a whole and for most zones in Maryland. In that auction, the capacity bids to meet PJM's requirements in Baltimore Gas & Electric's service territory zone—called the "BGE LDA"—fell just short because two plants in the BGE LDA—the Brandon Shores and Wagner power plants—had announced an intention to retire and did not bid into the auction.

PJM ensured reliability in the BGE LDA for the 2025/2026 delivery year by entering into "reliability must-run," or "RMR" arrangements with Brandon Shores and Wagner. The RMR arrangements obligate the plants to stay online past their intended retirement date and generate power until planned transmission enhancements add new import capabilities to replace, and potentially improve, system reliability following the retirement of the generation plants. It is reasonable to conclude that the BGE LDA will not have resource adequacy—or reliability—issues for the foreseeable future because of the RMR arrangements. The RMR arrangements will stay in-place until the planned transmission enhancements are built and fulfill the generation lost by these plants' retiring.

Under RMRs, generators commit to postpone their power plants' retirement date in exchange for a guaranteed payment which is almost always higher than the capacity market price. However, the performance commitments for RMR units are significantly less than for resources offered in the capacity market, and their exclusion from the capacity market could increase the capacity market price.

Following the summer 2024 auction, OPC and many others challenged PJM's policy that excluded Brandon Shores' and Wagner's RMR units from the auction. Faced with these challenges, PJM asked FERC to approve a change in policy to include RMR units in the future auctions. FERC approved this change for future annual capacity auctions, but not for the already completed auction for the 2025/2026 delivery year.

OPC released a report on the 2024 capacity market auction, the RMR arrangements, and their impacts on customers in August 2024.[1] Additionally, in April 2025, OPC filed with FERC a complaint seeking to reset the prices for PJM's July 2024 capacity auction and refund customers unreasonable and unnecessary capacity costs stemming from that auction. The complaint alleges the capacity costs were unreasonable because under the rules for the 2025/2026 delivery year, customers are paying for the capacity of the RMR power plants twice: once through the inflated capacity market prices, and again through the RMR arrangement that also ensures the units act as capacity.

What is the resource adequacy situation for next year?

PJM's capacity auction in July 2025 cleared just over the projected reliability requirement for the 2026/2027 delivery year, which runs from June 1, 2026, to May 31, 2027. As forecasted, the projected data center electric demand growth drove the capacity market price for the entire PJM region even higher than the previous delivery year's auction. The price reached a FERC-approved price cap of $329.17/MW-day that followed a complaint and settlement between PJM and the Pennsylvania governor. The $329.17/MW-day price represents a 22 percent increase over the previous year's auction. Without the price cap, the capacity auction would have cleared at $388.57/MW-day. Continued load growth, driven to a major extent by power demands of new data centers, is expected to continue to make the PJM region's supply-demand balance tight over the next few years.

However, data shows that from 2015 to 2024, Maryland's resource adequacy has not worsened despite past power plant retirements. In fact, because the demand for electricity had actually decreased over those ten years, Maryland's supply-demand balance has improved by over 200MW during that time.[2]

How are data centers impacting resource adequacy and customer costs?

According to the independent market monitor for PJM, data center load growth is "the primary reason for recent and expected capacity market conditions" within PJM. Most increases in demand in PJM's July 2025 capacity auction originated from projected data center electricity growth, totaling more than 5,400 MW of increased demand from the level of demand that cleared the previous year. As a result, PJM's capacity auction set an all-time record high clearing price of $329 per megawatt-day in July 2025, up from June 2024's $270/MW-day clearing price which itself was a nine-fold increase from the previous year. The increased costs resulting from the June 2024 capacity auction started

[1] Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland, OPC (August 2024).
[2] For sources and further context for this data, see OPC's Post Technical Conference Comments, FERC Docket No. AD25-7-000 at 18.

impacting residential customers' bills in July 2025. For BGE customers, the PSC ordered that the costs will only be in residential customers' bills in September through November 2025 and March through May 2026. The capacity costs from the July 2025 auction will hit utility bills sometime after June 1, 2026.

Similarly, PJM's auction in December 2025 also hit a record high. The clearing price in that auction was $333 per megawatt-day. The costs from this auction will be reflected in all residential customers' bills sometime after June 1, 2027.

Capacity costs are just one category of costs that data centers impose on residential customers. Data centers increase energy costs and transmission costs that are felt across PJM. For transmission costs, the current methodology for charging customers for new transmission projects results in jurisdictions geographically closest to the load growth paying a higher portion of the costs, even if those customers are located in another state. Driven by Northern Virginia's data center growth, Maryland customers will be responsible for hundreds of millions of dollars for transmission projects to address the added demand these data centers generate. OPC continues to fight the cost allocations driven by out-of-state data centers. For energy costs, a recent pricing analysis similarly suggests that data centers impose disproportionately higher energy costs on customers that are located close to areas of significant data center growth. Evidence suggests that data centers impose disproportionately higher energy costs similarly customers closest to the data centers.[3] For more information, read our press releases here, here, here, and here.

What are the future prospects for resource adequacy in Maryland?

Maryland appears to have sufficient resource adequacy over the near- and medium-term to meet the peak demands on its system. Transparent and objective efforts, some of which may be underway, to analyze future contingencies would be prudent.[4] Any assessment of Maryland's resource adequacy should include an assessment of both generation resources located within each of the LDAs in Maryland and an assessment of the ability of the transmission system to transfer power into the LDAs. It should also include other measures such as demand response and energy storage, accounting for existing tools the Public Service Commission has, to mitigate resource adequacy issues.

PJM ran its latest capacity auction in December 2025 for the 2027/2028 delivery year that runs June 1, 2027, to May 31, 2028. PJM included over 13,000 MW of projected load growth for data centers in that auction. About 100 MW of the 13,000 MW growth is forecasted for zones that include central and eastern Maryland. PJM projects about 400

[3] Josh Saul, Leonardo Nicoletti, et al, "AI Data Centers Are Sending Power Bills Soaring," Bloomberg (Sept. 29, 2025), https://www.bloomberg.com/graphics/2025-ai-data-centers-electricity-prices/?srnd=undefined.

[4] Public Service Commission PC66, Comments of the Office of People's Counsel (Jan. 17, 2025).

MW of growth for the Frederick area. The auction procured more capacity than the projected peak load for the entire PJM region but not as much as the projected peak load plus the PJM's reserve margin. The capacity procured provides for a 14.4 percent reserve margin for the region, which falls short of PJM's goal of a 20 percent reserve margin or about 8,453 MW of installed generation capacity.

PJM will run another "incremental" auction in February 2027 to procure additional capacity for the 2027/2028 delivery year. The amount of capacity PJM will seek to procure to meet its goal of a 20 percent reserve margin will be based on PJM's 2026 Load Forecast, released on January 14, 2026, in which it reduced its demand forecast for the entire region in 2027/2028 by about 3,700 MW (about the size of Pittsburgh, PA). PJM's reduction in its 2026 forecast will lower the amount of capacity PJM is seeking to procure in the incremental auction. PJM has not yet published the amount of the reduction. Additional capacity may be available in that auction. That additional capacity could come from new generating stations that were not sure they would be online by 2027/2028 or demand resources or plants delaying retirement that did not participate in the auction.

For Maryland zones served by the Exelon utilities, PJM is now forecasting that peak loads will decrease for BGE, Pepco, and Delmarva Power through 2029. The forecast has loads growing after that with a cumulative increase by 2032 of 118 MW for BGE and 482 MW for the Pepco zone. These increases are attributed to proposed data center projects.

PJM is forecasting data center demand growth for the Frederick area of almost 2,000 MW of load growth by 2032. Frederick is served by Potomac Edison, a subsidiary of FirstEnergy. PJM's forecasts of average annual demand growth through 2045 for the other Maryland zones other than western Maryland —including the BGE zone—are modest. For the BGE zone, the annual growth is forecast to be 0.9% or less. The annual growth forecast for the Pepco zone is 2.1% or less, and it is 0.4% or less for the Delmarva Power Zone. The load growth that is forecast for these zones is also primarily from data center proposals.

For the entire region, PJM forecasts over 42,000 MW of load growth by 2032. This tremendous amount of data center load growth outside of Maryland is creating challenges for the wholesale electricity market and for resource adequacy at the regional level. OPC (as well as other customer representatives) has made proposals in regional and federal forums that make data center customers responsible for the costs and reliability impacts that could be caused by their being connected to the grid without additional resources to serve them. Because of the scale of the data center projects and the speed with which they can potentially come on line, data-center customers should be responsible for the costs and reliability risks they are causing and other customers should not be burdened with the high capacity costs that are resulting from the forecast of very high growth in data center load.

Governor Moore, along with the other twelve governors in the PJM region and the National Energy Dominance Council within the White House, recently signed a "Statement of Principles Regarding PJM" that calls for assigning costs and reliability risks caused by data-center load growth to data-center customers and protecting other customers from those costs and risks.[5] While there are many steps remaining to get to a good result for residential customers, we are hopeful that this movement will lead to a reduction in future capacity prices.

Two Maryland generating plants, Brandon Shores and Wagner, have announced deactivations. As discussed below, those plants are remaining online until PJM's transmission solutions that remedy the resource-adequacy impacts of those retirements are in service.

Beyond the future retirements of the generating units at Brandon Shores and Wagner, most currently operating Maryland-generating plants are unlikely to retire soon. All of Maryland's coal-fired power plants have already retired or announced plans to retire. The possible exceptions are the natural gas and oil-fired units at Chalk Point in Prince George's County. Like Brandon Shores and Wagner, the Chalk Point units have been selling little energy, but have been available to help the system meet peak needs. While Maryland should be considering the possibility that the Chalk Point units will retire, current market conditions make retirement less likely. In fact, the Warrior Run plant located in western Maryland, which formally retired on June 1, 2024, recently obtained an approval from FERC to allow it to participate in future capacity auctions. Finally, higher capacity market prices across PJM also are incentivizing plants to remain online or come out of retirement.[6]

What is the plan for replacing the Brandon Shores and Wagner power plants near Baltimore?

Following Talen Energy Corp.'s announced plan to retire its coal-fired Brandon Shores power plant near Baltimore, PJM performed an analysis that found the retirement would cause reliability issues. PJM thus approved major transmission projects to be completed by the end of 2028 while customers pay under RMR arrangements to keep Brandon Shores on-line until that time (see FAQ "What is the resource adequacy situation now?"). The Brandon Shores deactivation projects include expanded transmission lines and additional facilities (such as static synchronous compensators or STATCOMs) for reactive services and other improvements to address the potential for voltage collapse.

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[5] *Statement of Principles Regarding PJM* (Jan. 16, 2026), https://www.energy.gov/documents/statement-principles-regarding-pjm.

[6] *See*, for example, Middle River Power reverses plan to shut 540-MW plant amid record PJM capacity prices, Utility Dive (Sept. 12, 2024). The plant discussed in this article is in Illinois.

The vast majority of the Brandon Shores deactivation projects were not competitively procured but awarded by PJM to Exelon and its Maryland subsidiary, BGE, through PJM's "immediate need" exception for competitive procurements. Exelon announced the award of the projects at its summer 2023 investor presentation as an $860 million project. The PJM Board approved the proposal at a cost of $780 million and sought FERC approval in August 2023. While not challenging the determination of reliability violations, OPC protested PJM's proposal for its failure to competitively procure the projects and to consider cost-effective alternatives, but FERC approved the projects as PJM requested. Subsequent modifications to PJM's regional transmission expansion plan changed one of the projects and reduced the price to $740 million. Most of the costs of the transmission projects will be paid for by BGE customers.

In January 2025, PJM reported that Exelon had updated its cost estimates for the Brandon Shores deactivation projects, doubling the costs from $740 million to more than $1.5 billion. BGE has not yet sought to include that higher level of costs in rates. When it does, OPC will evaluate whether to challenge the costs of the project before federal regulators.

How will the new transmission projects address the retirement of the Brandon Shores power plant's impact on resource adequacy in Maryland?

As part of the ongoing certificate of public convenience and necessity proceeding (CPCN) before the Public Service Commission, OPC is evaluating the benefits of the transmission projects for replacing Brandon Shores' generating capacity, particularly in light of their more than $1.5 billion in costs. To help its evaluation, technical experts for OPC performed computer power flow analyses that simulate PJM's reliability analyses.

The power flow analyses show the Brandon Shores deactivation projects will significantly increase Maryland's import capability—sufficient to accommodate at least 2,980 MW of load growth. This planned transmission solution's estimated capacity would exceed PJM's projected 2028 peak load in Maryland's service territories by more than 24 percent.

BGE's discovery responses, its testimony, and PJM statements in the CPCN case before the Commission appear to confirm OPC's analysis, qualitatively. A witness for BGE has described the transmission facilities as "drastically increas[ing] the import capability into the BGE service territory." Despite OPC's requests, as of August 2025 neither BGE nor PJM have provided their own analysis of the impacts of the $1.5 billion in transmission upgrades.

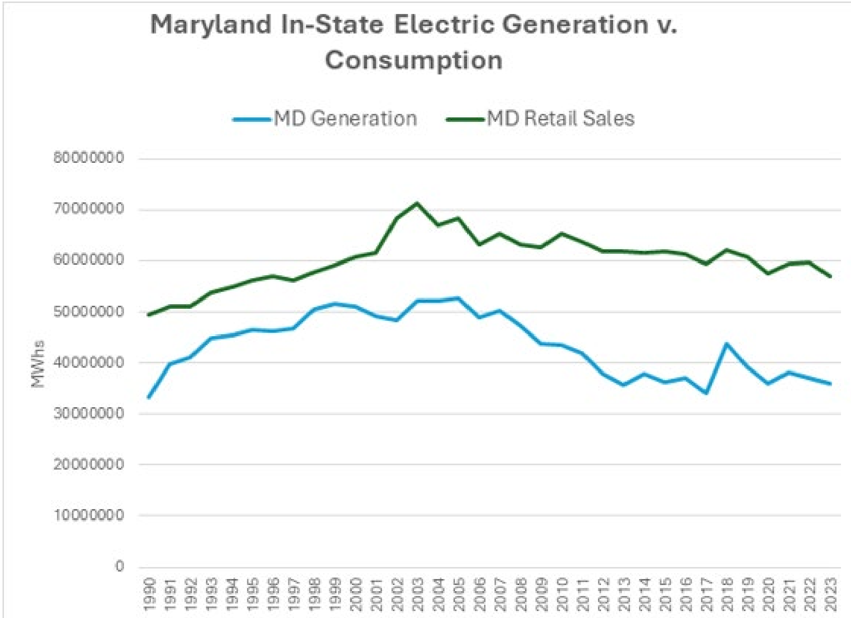
Does Maryland's status as a "net importer" of generation mean more in-State generation is needed for resource adequacy?

No. Resource adequacy depends only in part on the geographic source of energy production. It is mostly a function of peak demand and the combination of generation and transmission capability to meet that demand. Maryland's status as a net importer speaks to overall energy consumption—at all times of day over the course of a year—and is measured in *megawatt-hours* (or kilowatt-hours), which is a different measurement than used for reliability and system capacity—*megawatts*. Meeting resource adequacy requires having sufficient *megawatts* available at times of highest demand on the system, while Maryland's status as a net importer of 40 percent of its *megawatt-hours* speaks only to overall energy consumption. Maryland's status is not a limitation, but results from economics and importing power from the cheapest generator regardless of geographic location. This was illustrated at times during the June 2025 heat wave when Maryland produced far more of its electricity from within the State than its annual average of 60 percent. During non-peak load seasons, Maryland at times even becomes a net exporter.

The relevant available data does not show that there is a near-term need for new generation located in Maryland for reliable electric service. The transmission system in place can import enough power to serve Maryland customers, and new transmission under development meant to replace retiring power plants will increase that capability.

Maryland has imported a portion of its power needs for many decades through both periods of high and low energy costs.[7] In fact, more states in PJM are energy importers than exporters. D.C. imports about 98 percent of energy, and Delaware about 57 percent. As long as there is enough capacity in the region and sufficient transmission to deliver the electricity, importing part of Maryland's energy needs poses no risk to Marylanders.

[7] *See* State Electricity Profiles, EIA, Table 10. Maryland has been a net energy importer of electricity every year since 1990 (the EIA only provides data going back to the '90s). In 2013, Maryland imported 30,881,323 MWh, or 46% of its total electricity from other states, the highest annual import to date. 1998 was the lowest year of imports since 1990, with 13,945,102 MWh, or 22% imported into the State. In 2023, 24,139,011 MWh, or 40% of the State's demand, was imported.



Maryland, like many states in PJM, has long imported some of the electricity it uses.

In fact, Maryland customers benefit from being part of a diverse regional system and market, and it has been part of PJM for more than 60 years.

It is true, however, that new generation is needed within PJM's broader footprint because of increasing demand from data centers and potential power plant retirements.[8] Maryland, however, cannot address regionwide resource adequacy issues raised by data center growth elsewhere in PJM without taking on significant costs and risks.

How can Maryland lower the costs of assuring resource adequacy for customers?

Even though it is likely that there will be sufficient resources in Maryland to meet resource adequacy standards, tight market conditions *throughout* PJM could lead to high prices for capacity impacting Maryland customers in upcoming years. A variety of solutions could enhance resource adequacy, reduce risks to customers of reliability issues, and reduce the chances of paying high prices for potentially unnecessary transmission and generation. These measures include:

- *Demand flexibility and response*. Foremost among solutions are measures to enhance demand flexibility and response. Demand response refers to programs that pay or credit consumers for decreasing their energy use during peak demand hours. Estimates from the EmPOWER future programming

[8] At least some of this demand may be illusory. *See*, e.g., Investors may overestimate benefits to utilities of datacenter boom, S&P Global (June 18, 2024). Regardless, because PJM has accepted projected load growth from data centers, the demand for capacity from the market has increased and will continue to increase.

work group indicate that it would be cost effective to deploy more than four times the amount of demand response utilities paid for in 2023.[9] Demand response can bid into PJM's capacity market, and so, in addition to decreasing the real-time cost of electricity, can decrease capacity costs for consumers.

The electric system is built for—and resource adequacy is measured based on—peak demands on the system. Programs that encourage consumption more evenly across the day would decrease peaks that drive resource adequacy needs and thereby decrease system costs.

- *Energy efficiency*. Maryland could also take measures to require more energy-efficient appliances. While energy efficiency can no longer bid into PJM capacity markets,[10] encouraging energy efficiency can still reduce capacity demand. Energy savings means that less capacity is needed to serve the lower peak demand, thus decreasing capacity costs, while also lowering customer bills. An analysis for the EmPOWER energy-efficiency programs found vast quantities of cost-effective energy-efficiency savings are available beyond what the current EmPOWER program alone can provide.

- *Existing transmission enhancements*. The transmission system is part of the resource adequacy equation. Limits on how much electricity can be delivered over any given transmission line are determined by the physical characteristics of the wire. Grid enhancing technologies, also called GETs, refer to a suite of new technologies that provide low-cost methods to make the most of existing transmission infrastructure. GETs can help defer, or even avoid, expensive construction of new transmission lines and enable more generation to connect to the system and serve customers. One study estimates that GETs could save $1 billion annually across PJM by 2033.[11]

- *Distributed Energy Resources (DERs)*. Greater deployment of DERs—such as rooftop solar, community solar, and batteries—can also promote resource adequacy and decrease capacity costs. DERs connect to the distribution grid—and not the transmission grid—and so are not impacted by the current delays in PJM's process for connecting generation at the transmission level.

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[9] Utilities procured 125 MW of demand reduction in 2024. *See* The EmPOWER Maryland Energy Efficiency Act Report 2025, Public Service Commission (June 2025), at 15. It would be cost effective to procure more than 500 MW of demand response. *See* Maryland GHG Abatement Study Final Response, Applied Energy Group (Dec. 2, 2022), at 40. Originally submitted to the PSC under maillog number 300426.

[10] On Nov. 5, 2024, FERC accepted tariff revisions from PJM that prevent energy efficiency from participating in the capacity markets. *See* Docket No. ER24-2995.

[11] GETting Interconnected in PJM, RMI (February 2024).

DERs can either participate as demand response—by allowing residential customers to draw energy from their battery or "behind-the-meter" solar, rather than the grid, during times of peak demand—or they can be aggregated in a "virtual power plant" (VPP) to act as a generator that can bid capacity into the capacity auction. Studies have shown that virtual power plants can provide great value to the grid, with one study finding that VPPs could save utilities $15-$35 billion in capacity investments over a 10-year period.[12]

- *Energy storage*. Energy storage can "firm up" the capacity value of intermittent renewable generation by allowing energy from solar and wind to be stored and later deployed at moments of peak demand. Energy storage can help avoid costly transmission-system upgrades by pre-flowing energy over a transmission line and storing it on the other side of the line prior to times of peak demand. When demand peaks, energy can then be supplied *both* over the transmission line in real time, and from the batteries.

- *Surplus interconnection service*. FERC approved a PJM proposal resulting in more robust surplus interconnection service (SIS), which could also promote resource adequacy and lower costs. Many generators—especially intermittent renewable generation—do not use their full allowable transmission capacity.

  More robust SIS would enable additional generating units to share the interconnection with existing generators so long as the combined generation does not export more than the existing generation's maximum allowed output at any given moment. SIS could allow solar and wind resources to add battery storage to their sites and significantly increase supply in the PJM capacity market. One study estimated that batteries utilizing SIS on existing PJM solar interconnections alone could unlock an additional 5,862 MW of capacity—an amount equivalent to about 90% of Maryland's largest utility's current peak demand.[13]

Are there other measures that Maryland should take to assess or address resource adequacy?

Maryland can require greater information about large customers—such as data centers—that plan to locate in Maryland and take measures to ensure that new big customers do not cause higher costs for existing customers. For example, Maryland could require large customers to provide for their own generation needs and contribute to State policies and programs such as the Electric Universal Service Fund, EmPOWER, and the State's clean

[12] Real Reliability: The Value of Virtual Power, Brattle (May 2023), at 25.
[13] ReSISting a Resource Shortfall: Fixing PJM's Surplus Interconnection Service (SIS) to Enable Battery Storage, ACORE (Sept. 18, 2024).

energy goals. Further, data centers that have flexible power needs could bring benefits to the system.

Also, the State could take actions to promote more accurate forecasts of future loads, and State agencies can advocate for beneficial changes to PJM and FERC policies. OPC is a very active member of PJM, engaging daily in PJM workgroups and processes and advocacy before the FERC.

Is now a good time for Maryland to require in-State generation?

No. Interest rates are high, supply chain challenges are ongoing, and the high prices in PJM capacity market are providing incentives to existing generation to remain online and new generation to come online without ratepayer backing. As has long been the case for Maryland, if it's profitable because it's needed, private generation companies can provide the investor backing to develop generation plants.

Moreover, any new baseload generation would take many years before commencing operations, likely more than six years and potentially longer, extending further out in time the uncertainty of calculating an appropriate cost that ratepayers would be committed to.

Further, the data on load forecasts is fraught with speculation. Demand growth is likely to "fail to materialize as forecast," a January 2025 analysis from Bank of America concludes, and when this happens, "there are significant risks to overbuild of resources with no demand to serve."[14] Without an immediate urgency, Maryland would be better off waiting to see how projections for increasing electricity demand in other parts of PJM play out.

Finally, as described above, *there is no immediate resource adequacy issue requiring Maryland to take action that risks further increases to utility customer bills*. Most Maryland utility customers are already facing some of the highest bills they've ever seen because of massive rate increases over recent years, as described in our June 2024 rates report (updated March 2025).

Would allowing Maryland's utility monopolies to build and own power plants enhance resource adequacy and, if so, at what cost?

As noted above, Maryland does not need to take action to encourage the building of large power plants within the State. While any generation may lower costs in the medium to long term, utility-owned generation would likely do so at a higher cost than relying on independent power producers to construct more generation in the competitive market or making the most of the alternatives described above. Since 1999 in Maryland, law allows

[14] US Power & Utilities: Year Ahead 2025: Is Past What's Prologue?, Bank of America (January 7, 2025).

utilities to build and own generation subject to Public Service Commission approval, but this law has not been utilized.

Allowing utilities to build generation poses significant risks to Maryland's utility customers, with few offsetting benefits.

First, utility ratepayers could bear uneconomic costs. Maryland ratepayers would still have to cover power plant costs (plus a profit margin) if the units sit unused because there are other lower-cost generators available to serve customers or they are incompatible with federal or State climate goals. Indeed, data shows that New Jersey customers narrowly avoided paying nearly a half billion dollars above the market over the last ten years because a proposal to build out-of-market generation was overturned by the courts.

Second, utilities have no inherent advantages in constructing generation over non-utilities other than their ability to recover all their costs—no matter how high—from their captive customers. Non-utility generation companies, in fact, purchase the equipment to build generating plants from the same vendors as a Maryland utility would. Also, many non-utility companies have much greater experience actually building generation, which utilities have not done for about three decades.

Third, utilities should focus on their core activities. Like any private enterprise with monopoly power, utilities want to expand their business activities into new areas—beyond their core competencies. Utilities frequently exceed their projected costs on matters within their core competencies, such as transmission and distribution. (See above about the costs of the Brandon Shores transmission replacement projects Exelon is constructing, for which the costs recently doubled to $1.5 billion.) Utilities are likely more challenged to contain costs for businesses in which they have little or no experience.

Fourth, any new gas plant will take years—likely much more than five years—to come online.[15] By that time, planned new transmission is highly likely to be completed that will be available to serve Maryland customers and would allow other generation sources to compete against—and potentially out-compete—a utility-owned generating plant, to the detriment of customers, as the New Jersey example shows.[16]

[15] *See* Silverman et. al, Outlook for Pending Generation in the PJM Interconnection Queue (May 2024) at 9, (finding that "[A]bsent significant reforms or market innovations, most projects entering PJM's queue today are unlikely to come online before 2030.").

[16] As of June 2025, there is 788 MW of capacity associated with projects that are not yet constructed but that do have signed interconnection service agreements (ISAs) in Maryland. These plants can come online and are not impacted by the queue delays. Queue delays are holding back a much larger tide of generation that wants to interconnect. There is 6,122.0 MW of capacity in the queue in Maryland, and 152,384.0 MW of capacity in the queue or under construction in PJM. *See* Serial Service Request Status, PJM.

Finally, although additional new generation anywhere in the PJM region potentially decreases capacity costs by increasing supply, in the case of utility-owned generation, customers themselves do not necessarily benefit from lower prices. Rate-regulated utilities—which have exclusive government monopolies and captive customers—are paid on a "cost-plus return" basis, and if the costs are higher than competitors' costs, the utility is generally entitled to recover those costs plus its return as a matter of law. And because there is great uncertainty with projecting generation market prices over the life of the power plant, it is not possible to know whether utility ownership of generation will benefit customers.

What *would* be certain, however, is that captive utility customers bear all the risks that the future costs paid to the utilities would be higher than market prices. That is the opposite of how risks are allocated currently to the investors of competitive generation companies.

Would it be different if Maryland directed its utilities to competitively procure new in-State generation through purchase power agreements?

Establishing a competitive procurement for generation rather than simply requiring utility generation investments would be more protective of utility customers because it would avoid some—though not all—of the problems described immediately above.

Most importantly, it would not avoid the guesswork about future market prices that puts ratepayers at risk. As the New Jersey example noted above illustrates, locking in prices with private generation companies means that customers do not benefit as much if future market prices are low. One simply cannot know what the future capacity and energy markets will do. As with utility ownership, what *would* be certain is that captive utility customers would bear all the risks that the future costs of the procurement would be higher than market prices.