Understanding Rising Transmission Costs in the District of Columbia

An Overview of Transmission Planning and its Impact on Electricity Customers in DC

Prepared for the District of Columbia Department of Energy and Environment and Office of the Attorney General

January 13, 2026

AUTHORS

Sarah Shenstone-Harris
Wooddynne Dejeanlouis
Sabine Chavin

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

EXECUTIVE SUMMARY I

1. OVERVIEW OF TRANSMISSION COSTS IN THE DISTRICT OF COLUMBIA 1
   - 1.1. Transmission Rate Trends in DC 3
   - 1.2. Transmission Project Cost Trends in PJM and DC 5
   - 1.3. PJM Transmission Planning Overview 8
   - 1.4. Types of PJM Transmission Projects 9
   - 1.5. Pepco Customer Bills and Transmission Charges 11

2. BASELINE TRANSMISSION PROJECTS 12
   - 2.1. Planning and Oversight Process 12
   - 2.2. Cost Allocation Approach 16
   - 2.3. Cost Drivers for Projects Allocated to DC 18
   - 2.4. Case Study: Brandon Shores Deactivation Project 22

3. SUPPLEMENTAL TRANSMISSION PROJECTS 25
   - 3.1. Planning and Oversight Process 25
   - 3.2. Cost Allocation Approach 26
   - 3.3. Cost Drivers for Projects Allocated to DC 26
   - 3.4. Supplemental Project Case Study 28

4. NETWORK UPGRADES 29

5. RECOMMENDATIONS 30

List of Figures

Figure 1. Map of PJM transmission zones 2
Figure 2. Map of Pepco's service area 3
Figure 3. Transmission rates for DC residential customers 4
Figure 4. Pepco NITS and TEC transmission rates from 2021–2025 5
Figure 5. Approved transmission projects in PJM, by project status and expected online year 6
Figure 6. Approved transmission project costs allocated to the Pepco transmission zone, by project status and expected online year 7
Figure 7. Approved transmission project costs allocated to the Pepco transmission zone, by project type and expected online year 11
Figure 8. Immediate and non-immediate project costs for approved baseline projects allocated to the Pepco transmission zone 15
Figure 9. Total baseline project costs that are allocated to the Pepco transmission zone, by their location (state), for projects with expected online dates from 2005 to 2032 16
Figure 10. Baseline transmission projects allocated to the Pepco transmission zone, by driver type and expected online year 20
Figure 11. PJM RTO historical and projected load 21
Figure 12. Pepco zone historical and projected load 22

List of Tables

Table 1. Baseline transmission projects allocated to the Pepco transmission zone 19
Table 2. Supplemental transmission projects located within the Pepco transmission zone 27
Table 3. Average project costs for supplemental transmission projects located in the Pepco transmission zone, by driver type, relative to the PJM-wide average 28

EXECUTIVE SUMMARY

Electricity customers in the District of Columbia (DC) face growing issues with energy affordability, for many different reasons. One key factor is rising costs for the electricity grid's transmission infrastructure—which ultimately leads to higher electricity bills for DC customers. Between 2021 and 2025, DC's transmission rates increased by 68 percent for the average residential customer (or 44 percent when adjusted for inflation). These rates are expected to continue increasing in the near term, driven by transmission upgrades both close to home in the Pepco transmission zone and across the entire region covered by the regional transmission operator, PJM. Understanding the drivers of these increases is a key step in developing plans to mitigate rising energy costs. This report examines recent trends in transmission costs and planning in PJM, with a focus on electricity customers in DC.

One glaring trend is a hefty jump in the energy demand (or load) that PJM forecasts for future years. Much of this is due to new data centers whose timing and locations are highly uncertain. DC's contribution to this projected load growth is negligible; PJM's 2025 regional load forecast for the Year 2030 jumped roughly 10 percent from the previous year's forecast, while the load for the zone containing DC decreased by 3 percent. Nevertheless, DC electricity customers will bear part of the costs for transmission projects needed to accommodate the region's new demand. DC agencies and other PJM stakeholders can work to ensure PJM's load forecasts are as accurate as possible, in part through improved transparency. They can also work across state lines to gather up-to-date information on where and when new data centers and other potential large load customers are likely to end up.

Another trend relates to the oversight and transparency of certain categories of transmission projects. For projects that transmission owners implement within a specific zone of PJM to meet local system needs, oversight and opportunity for stakeholder engagement is more limited than for the region-wide projects overseen by PJM. These local projects, called supplemental transmission projects, now comprise a larger portion of projects throughout PJM than they used to: they make up 42 percent of historical and in-service projects but over 55 percent of planned projects. As the number (and average cost) of these local projects rise, customer bills are showing the impact. The transmission rate that includes supplemental project costs (the Network Integration Transmission Service rate) increased by 115 percent from January 2021 to June 2025 for the Pepco zone. DC and other stakeholders in the region can coordinate to advocate for better oversight and challenge the prudency of these costs.

More generally, DC agencies and other stakeholders in the region can participate actively in PJM and FERC transmission proceedings to improve planning processes, including in areas such as project prudency and cost allocation methodologies, to ensure that transmission costs are fair and appropriate and that the system is not overbuilt.

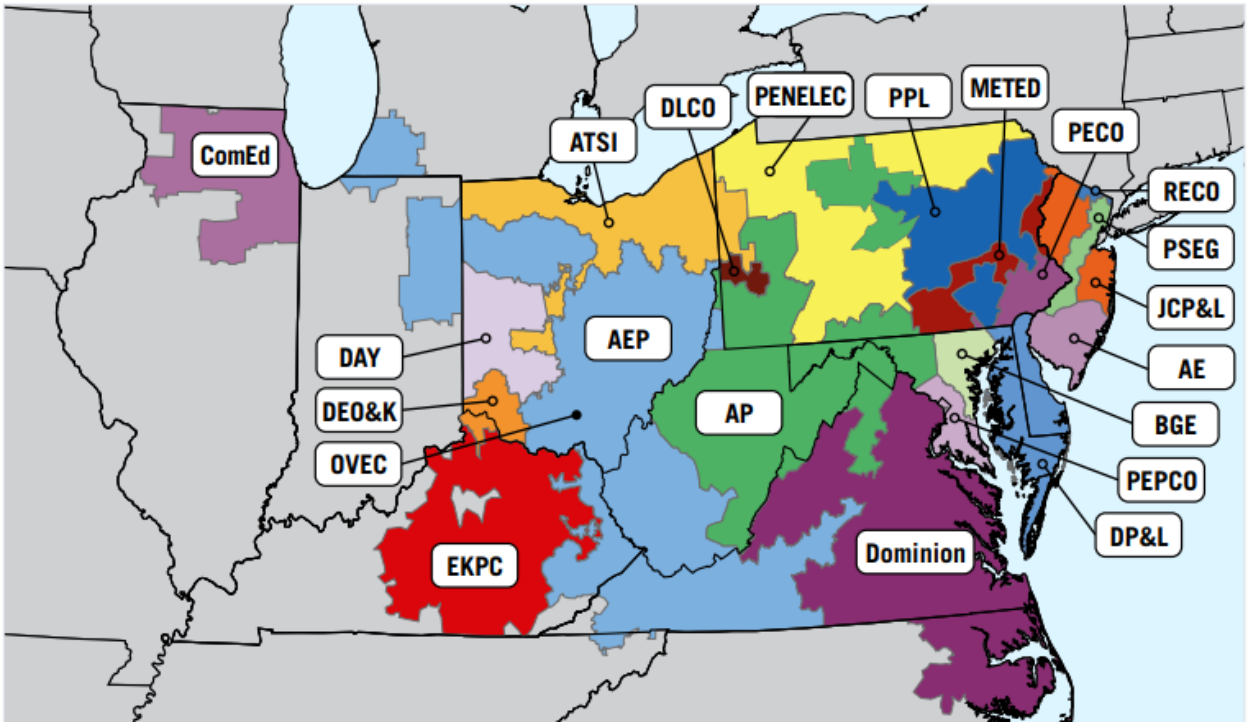
1. OVERVIEW OF TRANSMISSION COSTS IN THE DISTRICT OF COLUMBIA

The transmission network is the backbone of the regional electric grid, transporting power from power plants and other energy sources to communities and businesses. It plays a critical role in balancing electricity supply and demand across larger geographical areas, which helps manage costs for consumers and maintain an efficient and reliable electricity system. For residential customers in the District of Columbia (DC), transmission rates have increased by 68 percent between 2021 and 2025 (or 44 percent when adjusted for inflation). This increase represents roughly 9 percent of a typical residential electric bill. The sharp rises in transmission costs seen in recent years are projected to continue in the near term. And they contribute substantially to the broader electric rate increases in DC that are making it harder for customers to pay their bills, as evidenced by high levels of customer arrearages. As of August 2025, 24 percent of Pepco's residential customers were behind on paying their electric bills.[1]

Current transmission system planning and wholesale market operations are overseen primarily by PJM Interconnection (PJM), the Regional Transmission Organization (RTO) that coordinates electricity markets and grid reliability across DC and 13 states. Transmission Owners (such as Pepco which includes DC) build and own their assets in their respective transmission zones, while PJM operates the lines, but does not itself own any transmission assets. Figure 1 shows the map of all the Transmission Owner service territories (i.e., transmission zones) across the PJM footprint.

[1] ARDIR – Information on Disconnections for Non-Payment. September 19, 2025. Pepco. DC PSC Case 813-1043. Available at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=230414&guidFileName=25ea9bfa-7545-4331-99b3-782de4f7c380.pdf

Figure 1. Map of PJM transmission zones



Source: PJM Interconnection, Library: Maps. Available at: https://www.pjm.com/library/maps.

The District of Columbia receives its electricity service from Pepco, which owns and operates the transmission and distribution infrastructure that delivers power into the city. Because there is minimal local large-scale generation within the District, nearly all electricity serving DC is imported through distribution and transmission lines within the Pepco zone or imported from other zones. As a result, transmission planning plays a critical role in ensuring reliability for the District. The Pepco transmission zone includes all of DC and portions of Maryland (Figure 2).

Figure 2. Map of Pepco's service area

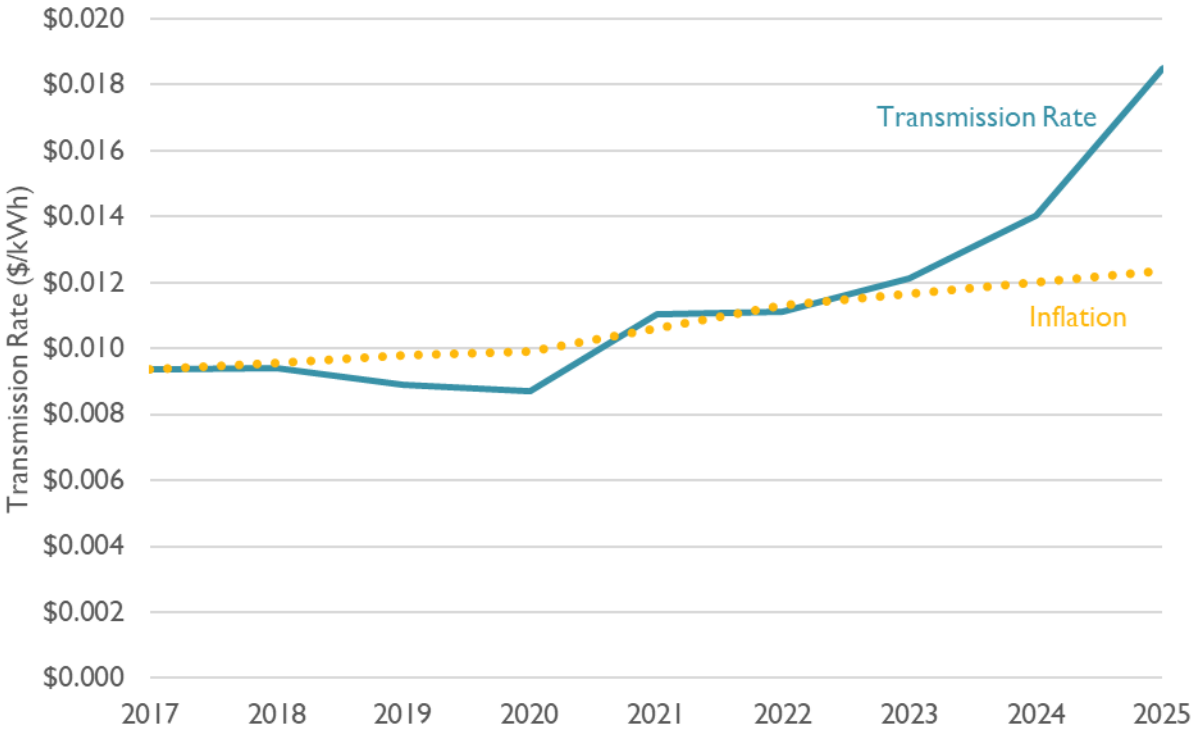
Source: Electricityrates.com. Available at: https://electricityrates.com/maryland/pepco/.

Transmission costs are determined by a combination of PJM, Transmission Owners, and ultimately, the Federal Energy Regulatory Commission (FERC), which regulates transmission rates. Within each transmission zone, the relevant Transmission Owner (i.e., Pepco) allocates these costs to load-serving entities (LSE) in its service territory based on formulas approved by FERC. LSEs are entities such as distribution companies and retail competitive suppliers that sell energy to end users. The LSEs in the Pepco transmission zone include Pepco's Maryland and DC distribution utilities, the Southern Maryland Electric Cooperative (SMECO), and numerous competitive retail suppliers in DC and Maryland.

1.1. Transmission Rate Trends in DC

Transmission rates for DC customers have been increasing rapidly, at a much faster pace than inflation (Figure 3). For residential customers, they increased by 68 percent between 2021 and 2025, or 44 percent when adjusted for inflation.

Figure 3. Transmission rates for DC residential customers



Source: Pepco tariffs and filings and Rate Acuity for residential SOS customers with 614 kWh monthly consumption.

The transmission charges that customers see on electric bills in PJM are made up of two key components: the Transmission Enhancement Charges (TEC) and Network Integration Transmission Service (NITS).[2] These charges include transmission project recoverable expenses such as construction, operations and maintenance (O&M), return on revenue, and taxes. PJM administers these transmission charges to Pepco and other Transmission Owners, who pass these costs onto the LSEs in their service territory, who in turn pass these costs onto their own end-use customers. Customers in DC pay 34 percent of costs allocated to the Pepco transmission zone, based on DC's contribution to the Pepco zone's total zonal peak load.[3]

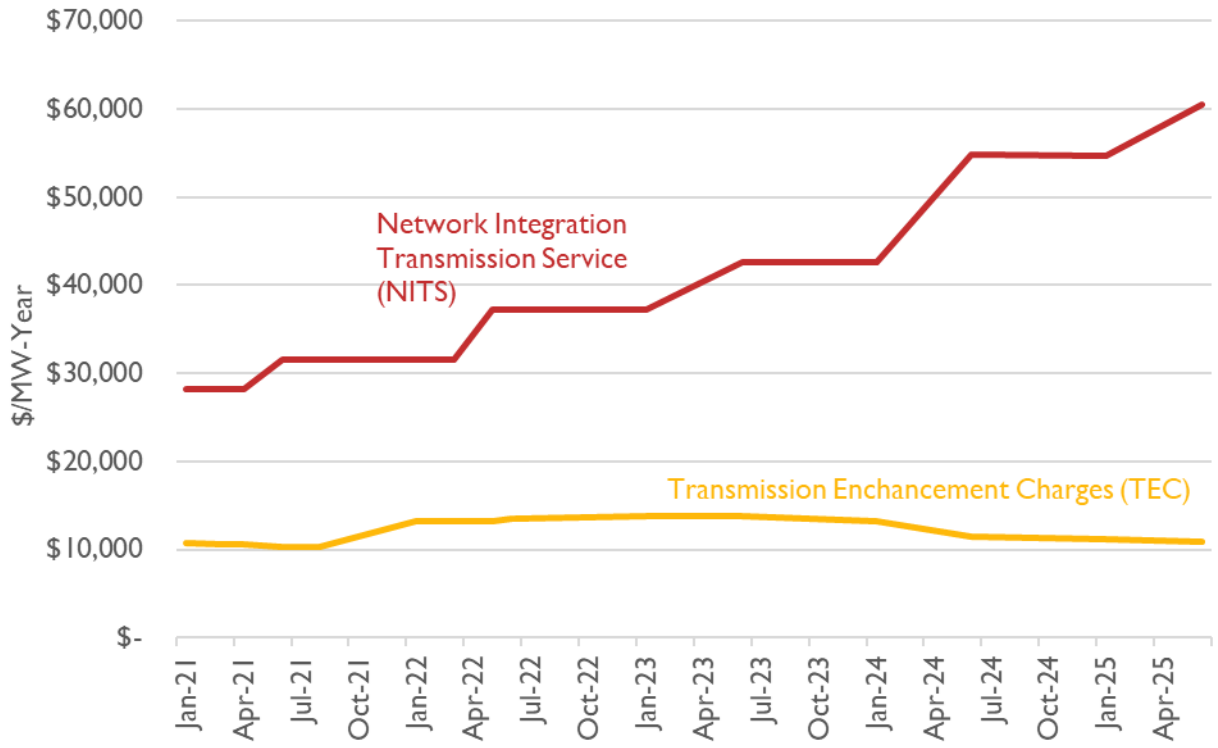
While the TECs in Pepco's territory have remained more or less constant, the NITS rates have not (Figure 4). Pepco's steadily rising NITS rates are ultimately pushing up transmission costs on utility bills (as seen above in Figure 3). In fact, NITS rates have increased by 115 percent from January 2021 to June 2025.

[2] A portion of the TEC that Pepco customers pay is included in Pepco's NITS zonal rate.

[3] Potomac Electric Power Company, District of Columbia Formal Case No. 1017, Response to DCG Data Request No.2. September 22, 2025.

The main drivers for these increasing NITS rates are the growing number and size of supplemental transmission projects across PJM, which we discuss in the next sections.

Figure 4. Pepco NITS and TEC transmission rates from 2021–2025

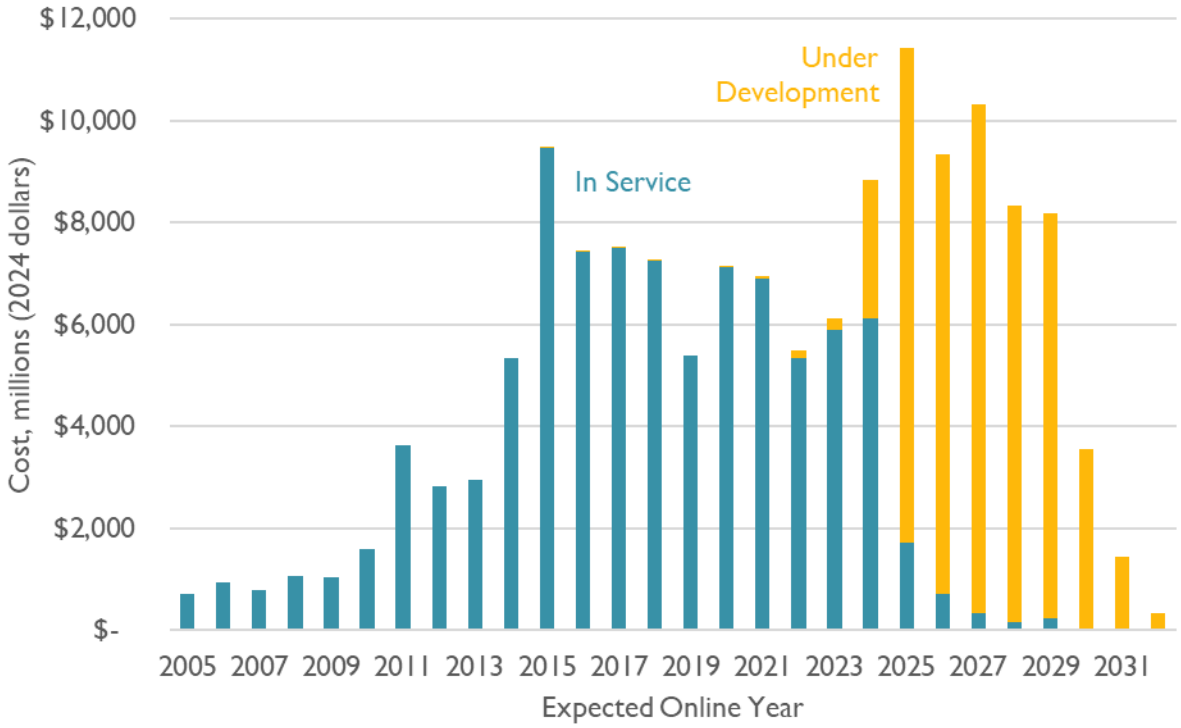


Source: PJM Billing, Settlements & Credit. Network Integration Transmission Service Revenue Requirements & Rates and Transmission Enhancement Worksheets. Available at: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.

1.2. Transmission Project Cost Trends in PJM and DC

Transmission rates are the mechanisms by which Transmission Owners recover the costs of specific transmission projects, which are the focus of this section. Transmission project costs have fluctuated over the past two decades, as grid needs have evolved over time. While transmission costs have declined in recent years since their peak in 2015, these project costs are expected to rise in the coming years (Figure 5). From 2005 to 2025, the in-service transmission projects for the PJM region as a whole cost roughly $82 billion (in 2024 dollars). PJM has approved an additional $51 billion (2024 dollars) in projects to be built in the next five years to meet emerging challenges, including aging transmission infrastructure, load growth from electrification and data centers, a fleet of increasingly aging and retiring generators, and a changing portfolio mix with a growing share of renewable energy resources that are more dispersed geographically than traditional large fossil fuel power plants.

Figure 5. Approved transmission projects in PJM, by project status and expected online year

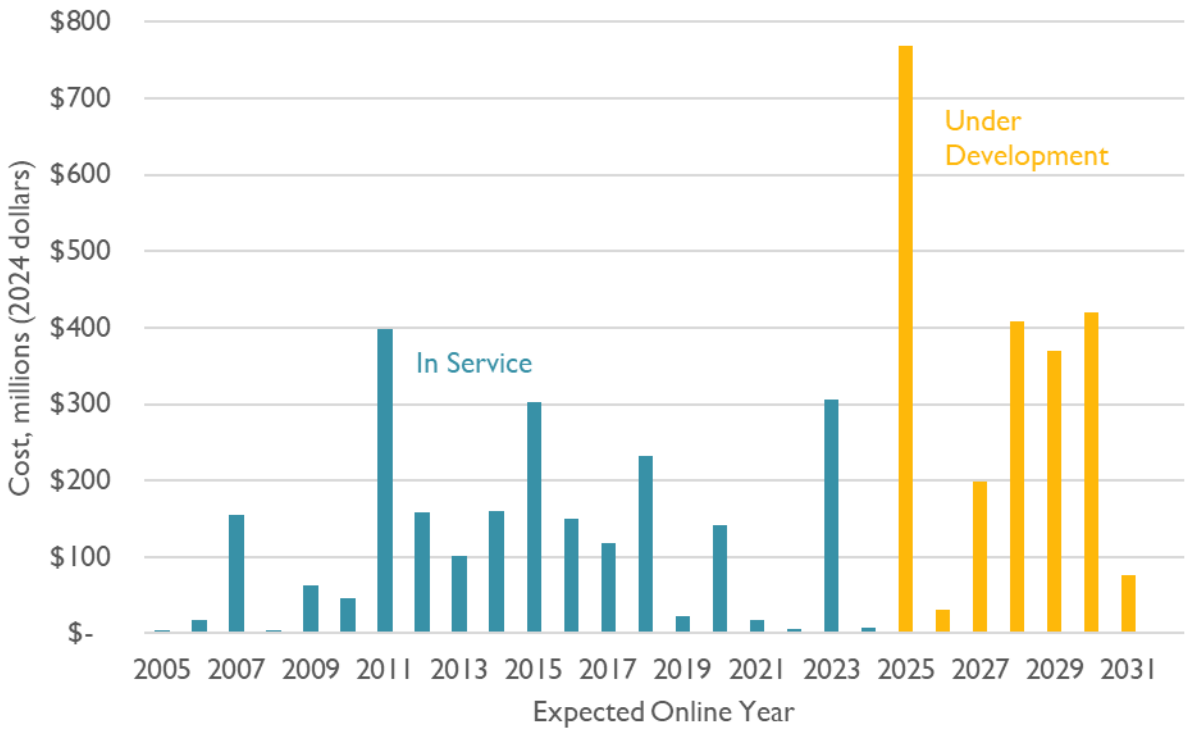


Note: PJM plans the transmission system through the RTEP process based on a 5-year horizon; the years after 2030 are therefore unlikely to be complete. Under development projects with an expected online date in the past are off-schedule or delayed. Figure includes approved baseline upgrades, network upgrades, and supplemental projects and excludes canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

The PJM Transmission Cost Planner (TC Planner) uses several categories to describe the status of transmission projects. In the figure above, projects labeled as "Under Development" include projects in the phases of "Under Construction," "Engineering & Procurement" (engineering, detailed design, material procurement, and resource planning), and "Planning" (projects that have been approved by PJM but are not yet in the "Engineering & Procurement" phase), as used in the TC Planner.

Of the $145 billion (2024 dollars) of in-service and under-development projects shown in Figure 5 (which include costs for the whole PJM region), customers or generators in the Pepco transmission zone pay for roughly 3 percent, or $4.5 billion. As with transmission costs across the PJM region, Pepco transmission costs are expected to increase in the next decade (Figure 6).

Figure 6. Approved transmission project costs allocated to the Pepco transmission zone, by project status and expected online year



Notes: PJM plans the transmission system through the RTEP process based on a 5-year horizon; the years after 2030 are therefore unlikely to be complete. Figure includes approved baseline upgrades, network upgrades, and supplemental projects and excludes canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

Importantly, transmission projects are paid for over their expected useful life through cost recovery mechanisms built into transmission rates. Depreciation schedules vary, but Pepco project costs are generally depreciated over time at a rate of approximately 2.5 percent.[4] This translates into an average service life of 30–40 years for the purposes of depreciation, meaning that customers are still paying for projects built decades ago. For example, a $100 million transmission line with a 3 percent annual depreciation rate would return $3 million per year in depreciation expense until fully depreciated. For 33 years, the depreciation costs associated with this project would continue to appear on NITS and TEC charges and customer bills until fully depreciated. Even after the capital expenses for a project are fully depreciated, the Transmission Owner would continue to have O&M expenses associated with the project (e.g., ongoing tree trimming) that would continue to be included in transmission charges.

[4] Pepco Holdings LLC. "Property, Plant and Equipment – Annual Depreciation Provisions as Percentage of Average Service Life (Details)," SEC XBRL Exhibit R83 (Dec. 31, 2021), U.S. Securities and Exchange Commission, XBRL document, Available at: https://www.sec.gov/Archives/edgar/data/78100/000110935722000076/R83.htm.

1.3. PJM Transmission Planning Overview

As noted above, PJM and Transmission Owners oversee current transmission system planning and wholesale market operations. FERC has jurisdiction over key aspects of transmission planning, including the review of proposed supplemental transmission projects and the approval of transmission rates that allow Transmission Owners to recover their costs. Transmission Owners build and own their assets, while PJM conducts transmission planning and operates the electricity grid and transmission lines. PJM, Transmission Owners, and FERC each play distinct roles in the planning, development, and oversight of transmission infrastructure.

The Transmission Owners in the Pepco transmission zone are SMECO and Pepco, which is a subsidiary of Exelon. Exelon's other utilities include Atlantic City Electric (New Jersey), Baltimore Gas & Electric (BGE) (Maryland), ComEd (Illinois), Delmarva Power (Delaware and Maryland), and PECO (Pennsylvania).[5] Each of these Exelon subsidiaries is a Transmission Owner in PJM (Figure 1).

Transmission Owners develop Local Transmission Plans (LTP) that include both baseline projects, which PJM reviews and incorporates into the Regional Transmission Expansion Plan (RTEP), and supplemental projects, which are driven by local needs and presented through PJM's stakeholder process but are not required to meet PJM-identified reliability, market efficiency, or public policy criteria. PJM also conducts its own regional studies to identify additional projects that address these criteria. For baseline projects identified through the LTPs or PJM's regional studies, PJM may initiate a competitive solicitation in which both incumbent Transmission Owners and nonincumbent developers can propose solutions, with PJM selecting the option that best addresses the identified need. Supplemental projects, by contrast, are not subject to competition; they remain the responsibility of the Transmission Owner to develop.

Transmission Owners, consumer advocates, market participants, and other interested stakeholders can participate in PJM's two transmission stakeholder forums: the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committees (i.e., Mid-Atlantic, Southern, and Western RTEP). Stakeholders provide input on identified needs, discuss study assumptions, and review proposed transmission solutions. While these committees are integral to PJM's transmission planning process, they serve in an advisory capacity and do not have decision-making authority (i.e., committee participants do not vote).[6] For baseline transmission project decisions, PJM staff make recommendations (informed by stakeholder feedback from these committees) to the PJM Board of Managers for approval. FERC provides final approval of supplemental projects.

More broadly, FERC provides the regulatory framework that governs PJM's transmission planning processes, primarily through its approval of PJM's tariff and its rulemakings such as Orders 890 and

[5] Exelon: Our Companies. Available at: https://www.exeloncorp.com/companies.

[6] In certain voting PJM stakeholder bodies, i.e., the Members Committee and Markets & Reliability Committee, Exelon and its subsidiaries (e.g., Pepco) vote as a single entity. In other voting committees, i.e. Standing Committees and Senior Task Forces, Exelon affiliates (e.g., Pepco) may vote separately.

1000, which require open, transparent, and non-discriminatory planning. More recently, FERC Order 1920 established new requirements for long-term regional transmission planning, which PJM will need to implement in its processes going forward. FERC also approves and monitors the cost allocation methods that determine how transmission project costs are shared, ensuring they remain just and reasonable. In addition, FERC regulates the financial aspects of transmission investment by approving transmission owners' allowed returns on equity (ROE) and rates of return, which directly affect project economics. Finally, FERC serves as the venue for stakeholders to challenge PJM's planning outcomes, with authority to remand or modify decisions, if warranted.

1.4. Types of PJM Transmission Projects

There are three main transmission project types in PJM, which each have their own distinct drivers, planning processes, oversight requirements, and cost allocation methods:

- **Baseline Upgrades**: Regional transmission projects, often crossing transmission zones or state borders, that are primarily needed to meet reliability standards. They may also be required for market efficiency, public policy, or operational performance reasons, such as addressing congestion or line overloads. PJM reviews these projects, incorporates them into the RTEP, and may subject them to competitive solicitations to allow both incumbent and nonincumbent developers to propose solutions. For each project, PJM is actively involved in validating the need, evaluating proposals, and approving the final selection.

- **Supplemental Upgrades**: Expansions or enhancements planned and developed by Transmission Owners to address local system needs, such as asset replacement, operational flexibility, or local load growth. PJM does not independently validate the technical need or oversee a competitive process for these projects; its role is limited to reviewing and posting the projects publicly through stakeholder forums (TEAC and Subregional RTEP Committees). Supplemental projects remain the responsibility of the Transmission Owner for planning, execution, and cost recovery.

- **Network Upgrades**: Transmission infrastructure additions or upgrades required to support the interconnection of new generators. These projects are typically triggered by generator interconnection requests and ensure that new resources can reliably connect to and operate on the transmission system. PJM reviews network upgrades to ensure interconnection reliability.

For baseline and supplemental transmission projects, Transmission Owners (such as Pepco) recover costs from wholesale customers including LSEs, distribution utilities, third-party power providers, and certain industrial customers through FERC-regulated charges. These wholesale customers then pass on the transmission costs to their electricity customers (homes and businesses in DC and across PJM). Network upgrade costs, on the other hand, are paid directly by the generator or interconnection customer; generator owners then seek to recover these costs from electricity customers by including these costs in their offer prices in the electricity markets.

For PJM overall, baseline and supplemental projects each make up roughly 45 percent of total transmission costs, while network costs make up the remaining 10 percent. However, the share of supplemental projects is growing across PJM, increasing from 42 percent of in-service projects to over 55 percent of approved projects (but not yet in-service). Consumer advocates across PJM have expressed concerns with the growing share of transmission costs represented by supplemental projects. For example, both the Organization of PJM States (OPSI) and the Consumer Advocates of PJM States (CAPS) have raised concerns regarding lack of transparency, regulatory oversight, and increasing costs associated with supplemental projects.[7]

Figure 7 shows the baseline, supplemental, and network project costs allocated to the Pepco transmission zone over time. For projects allocated to the Pepco zone, baseline projects made up the vast majority of projects until 2017. From 2018 to 2026, there were (or will be) almost no new baseline projects. For this period, supplemental projects almost exclusively drive transmission costs for the Pepco zone. Going forward, beyond 2026, baseline projects increase, driven by regional load growth and power plant retirements (Figure 7). PJM's Transmission Cost Planner does not yet include substantial amounts of new supplemental projects for the Pepco zone, though Pepco has presented additional supplemental projects to the PJM TEAC that may be included in the future.[8] Network upgrade costs (paid for by generators and interconnection customers) represent less than 1 percent of transmission projects within the Pepco transmission zone (Figure 7).

As seen in Figure 7, there is a large spike in supplemental projects costs expected for 2025. For the Pepco zone in 2025, there are 10 approved projects listed in PJM's Transmission Cost Planner, with one project representing 89 percent or $685 million (in 2024 dollars) of that total 2025 sum. That single supplemental project represents transmission substation and line upgrades associated with the Capital Grid Project.[9] The Capital Grid Project, as a whole, includes both transmission upgrades (supplemental PJM project) and distribution infrastructure (lower voltage assets that connect to PJM's transmission grid, but are overseen and regulated locally by entities like the DC Public Service Commission, or PSC).[10]

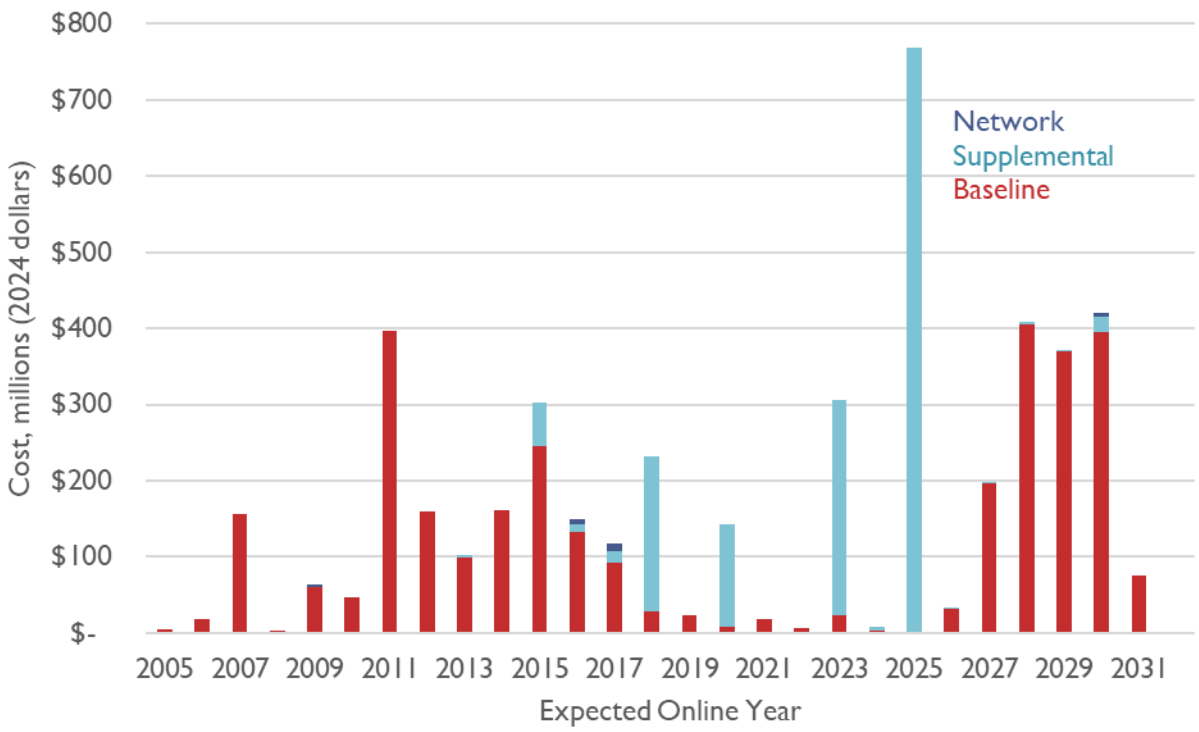
[7] For example, OPSI, 2023, Transmission Planning and Cost Management, FERC Docket No. AD22-8-000, or OPSI, 2021, Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, FERC Docket No. RM20-10.

[8] Exelon. September 9, 2025. Transmission Expansion Advisory Committee, PEPCO Supplemental Projects. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250909/20250909-item-11---pepco-supplemental-projects.pdf.

[9] PJM Interconnection. November 20, 2015. Sub regional RTEP Committee Mid-Atlantic. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/srrtep-ma/20151208/20151208-reliability-analysis-update.pdf.

[10] DC Public Service Commission. Capital Grid Project. Available at: https://dcpsc.org/Utility-Information/Electric/Capital-Grid-Project.aspx.

Figure 7. Approved transmission project costs allocated to the Pepco transmission zone, by project type and expected online year



Notes: PJM plans the transmission system through the RTEP process based on a 5-year horizon; the years after 2030 are therefore unlikely to be complete. Figure does not include canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

This reports discusses baseline, supplemental, and network upgrade transmission projects in their own sections below, including how these projects are planned, drivers of and needs for these project types, what level of regulatory oversight they receive, and how costs are ultimately allocated to customers in DC and the broader PJM footprint.

1.5. Pepco Customer Bills and Transmission Charges

The Transmission Owner (i.e., Pepco) allocates transmission costs through the NITS and TEC to LSEs in its service territory, which include both distribution companies (Pepco) and retail competitive suppliers. For its standard offer service (SOS) customers (customers on the default service), Pepco recovers NITS and TEC charges by first allocating the total transmission revenue requirement to each retail rate class based on that class's contribution to the zone's Network Service Peak Load (NSPL).[11] Classes with higher

[11] The NPSL is the metered demand coincident with zonal peak load hour, not coincident with the PJM system peak.

coincident peak demand are assigned a proportionally larger share of the cost. For large commercial and industrial customers with demand meters, these costs are recovered through a demand charge ($/kW, aligned with the NITS and TEC rate structure). For residential and other non-demand-metered classes, Pepco converts the class-level transmission obligation into a volumetric charge by dividing the allocated dollar amount by forecasted class energy sales, producing a $/kWh transmission rate. These demand or volumetric transmission charges, which are reviewed and approved by the PSC, appear in the supply portion Pepco customer bills. In recent years, DC customers have seen these transmission charges on their bills rising (as discussed above in Figure 3). Given the growing number of projects expected in the next few years that are allocated to the Pepco transmission zone, especially baseline projects and Pepco's proposed new supplemental projects, it is likely that these rates will continue to increase.

2. BASELINE TRANSMISSION PROJECTS

Baseline upgrades, also known as regional transmission projects, typically cross transmission zones or state borders. In PJM, baseline upgrades are planned through the RTEP process, where PJM evaluates long-term transmission needs and assesses the necessity of large-scale and capital-intensive transmission projects well in advance of construction.[12] These types of transmission projects are driven by three primary factors: reliability, economic efficiency, and public policy.[13] Reliability projects ensure compliance with North American Electric Reliability Corporation (NERC) standards and other grid reliability criteria, including in response to increasing demand for electricity. Economic efficiency projects are designed to reduce electricity costs for consumers, such as by alleviating congestion on the transmission system. Public policy projects arise from federal, state, or local laws and regulations. For example, renewable portfolio standards (RPS) may require new transmission lines to integrate renewable energy resources. In practice, a single transmission project may be justified by multiple drivers simultaneously, and the PJM tariff accordingly allows for multi-driver planning.

2.1. Planning and Oversight Process

The PJM RTEP involves two key steps: first, determining system needs, and second, identifying solutions to address those needs.

[12] PJM Interconnection LLC. 2025. *RTEP: Planning for Long-Term Transmission Needs*. PJM.https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/rtep-fact-sheet.pdf.

[13] David Gardiner & Associates. 2024. CAPS Transmission Handbook, Volume IV: Transmission Planning in PJM. February 2024. Washington, DC: Consumer Advocates of the PJM States.https://www.dgardiner.com/wp-content/uploads/2024/03/CAPS-Transmission-Handbook-Volume-4.pdf.

Determining transmission needs

The first step in the regional planning process, determining transmission needs, requires PJM to conduct a series of power flow and reliability studies to identify when and where the grid is constrained. These studies examine a range of technical issues, including thermal overloads, voltage violations, excessive short-circuit currents, generator stability, and congestion.[14] PJM incorporates into its models and forecasts the latest data on load growth including demand response, energy efficiency, electrification, and the impact of new data centers. Other key model inputs include anticipated generation additions and retirements, transmission topology, and bilateral contract arrangements.

PJM's transmission needs studies occur on several timelines. Annual studies with a five-year planning horizon address near-term reliability concerns, while biennial studies evaluate longer-term reliability issues. In addition, PJM is developing a new Long-Term Regional Transmission Planning (LTRTP) framework, as required by FERC Order 1920 in May 2024. The LTRTP extends the planning horizon to 20 years and must be updated at least every five years. It requires PJM to use multiple forward-looking scenarios that account for state energy policies, projected load growth, electric vehicle adoption, resource retirements, and clean energy targets. PJM is currently in the process of implementing this new framework through updates to its planning manuals and procedures.

Through this initial step, PJM will also identify whether the transmission need is immediate or non-immediate. Immediate need projects are transmission upgrades that must be completed within three years or less to resolve a time-sensitive reliability violation, while non-immediate-need projects have longer development timelines (usually over five years).

Load forecasts are a major driver of transmission needs. However, by their forward-looking nature, load forecasts always include some uncertainty. Currently increasing that uncertainty are fast-paced, large developments related to data centers. Data center developers often submit large load interconnection requests in multiple jurisdictions, leading to potential double-counting of loads between states and utilities. In addition, technology developments related to data center software and hardware change rapidly, which impacts assumptions about how much each electricity each data center might consume, as well as the flexibility of that load. This uncertainty is reflected in year-on-year fluctuations in PJM load forecasts. From the 2024 load forecast to the 2025 one, PJM's projection for the overall RTO peak in 2030 increased by approximately 10 percent, from 168 GW to 184 GW. Meanwhile, PJM's projection for the Pepco zone's 2030 peak load decreased by 3 percent, declining from 6,337 MW down to 6,167 MW between these two forecasts. The magnitude of the uncertainty and year-on-year fluctuations in PJM's current load forecasting process are creating risks of overbuilding transmission assets for load that may not materialize, potentially resulting in stranded asset costs that would need to be recovered from electricity customers. In other words, electricity customers may end up paying for unnecessary projects.

[14] PJM Interconnection LLC. 2023. *Regional Transmission Expansion Planning: Meeting the Grid's Future Needs*. March 2023. https://www.pjm.com/-/media/DotCom/library/reports-notices/2023-rtep/rtep-meeting-the-grids-future-needs.pdf

Improving the accuracy of load forecasts and addressing concerns around double-counting or other potential sources of overestimation will help improve trust in the transmission planning process.

Identifying transmission solutions

Once transmission needs are identified, PJM and its Transmission Owners identify the transmission solutions. This process differs for immediate and non-immediate needs projects.

Non-immediate need projects

PJM conducts a competitive proposal process for non-immediate needs projects, whereby PJM opens a proposal window based on project requirements such as the in-service date, voltage level, and expected scope of solutions.[15] Both incumbent and non-incumbent developers (such as merchant companies) can then propose transmission solutions to address the specific need. After the window closes, stakeholders review proposals through the TEAC and subregional RTEP committees; stakeholders can provide input but cannot vote on the proposals. PJM staff then evaluate all proposals to ensure they meet reliability and constructability requirements and then recommend a selection of RTEP projects for the PJM Board to approve. The PJM Board holds the authority to question prudence of projects and selects projects based on a set of qualifications, including cost-effectiveness. The Board will approve the projects if they are consistent with PJM's Operating Agreement requirements.

The most recent competitive proposal window in PJM's RTEP was 2024 RTEP Window 1, which opened in July 2024 and closed in September 2024. PJM's Board approved a portfolio of selected projects in February 2025, totaling nearly $6 billion in baseline reliability investments, including new 765 kV regional reinforcements alongside many other upgrades.[16] Other recent major transmission expansion plans include PJM's recent 2022 RTEP Window 3, where PJM selected projects totaling approximately $5 billion.[17] PJM's Board approved the 2022 RETP Window 3 portfolio in December 2023 to address powerplant deactivations and increasing demand for data centers in areas such as Northern Virginia. PJM opened its latest 2025 RTEP Window 1 from June to August 2025. PJM will present its selection to stakeholders in November 2025 through January 2026, with final board approval expected in early 2026.[18]

---

[15] *Id.,* at 3

[16] PJM Interconnection. February 26, 2025. PJM Board Approves New Transmission Projects To Support Grid Reliability. PJM Insider Lines. Available at: https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

[17] PJM Interconnection. January 13, 2025. FAQ: PJM's Role in Regional Planning and RTEP Windows. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/postings/faq-rtep-2022-window-3-2024-window-1.pdf.

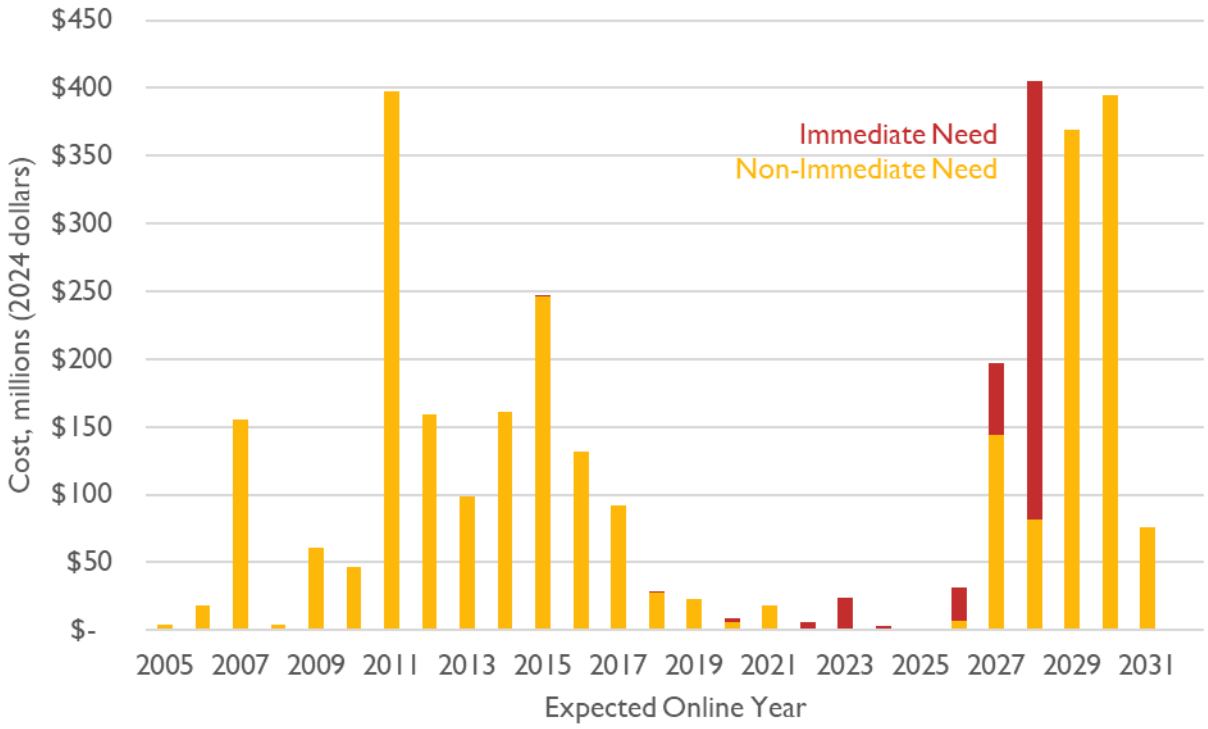
[18] PJM Interconnection. September 9, 2025. Reliability Analysis Update. Transmission Expansion Advisory Committee. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250909/20250909-item-16---reliability-analysis-update.pdf.

Immediate need projects

Because immediate need projects are needed within three years to address urgent transmission violations, a full competitive proposal window may take too long and pose reliability risk to the region. As a result, projects deemed immediate need are exempt from the competitive process. PJM directly selects incumbent Transmission Owners to develop and own the transmission upgrade.

Most projects, both in PJM and for the Pepco transmission zone, are non-immediate needs projects and are subject to the competitive process. Specifically, 87 percent of baseline project costs allocated to the Pepco zone (including baseline in-service projects and projects approved for the future) were procured competitively. However, there has been a recent increase in immediate need projects, which are not competitive and thus at risk of costing more than necessary (Figure 8). The vast majority (84 percent) of immediate need project costs allocated to Pepco are driven by one project alone: the Brandon Shores Deactivation Project (see its Case Study in Section 2.4). The second largest driver (12 percent) for immediate need project costs are Transmission Owner criteria violations, where upgrades are required to satisfy more stringent local reliability standards beyond PJM's minimum criteria.

Figure 8. Immediate and non-immediate project costs for approved baseline projects allocated to the Pepco transmission zone



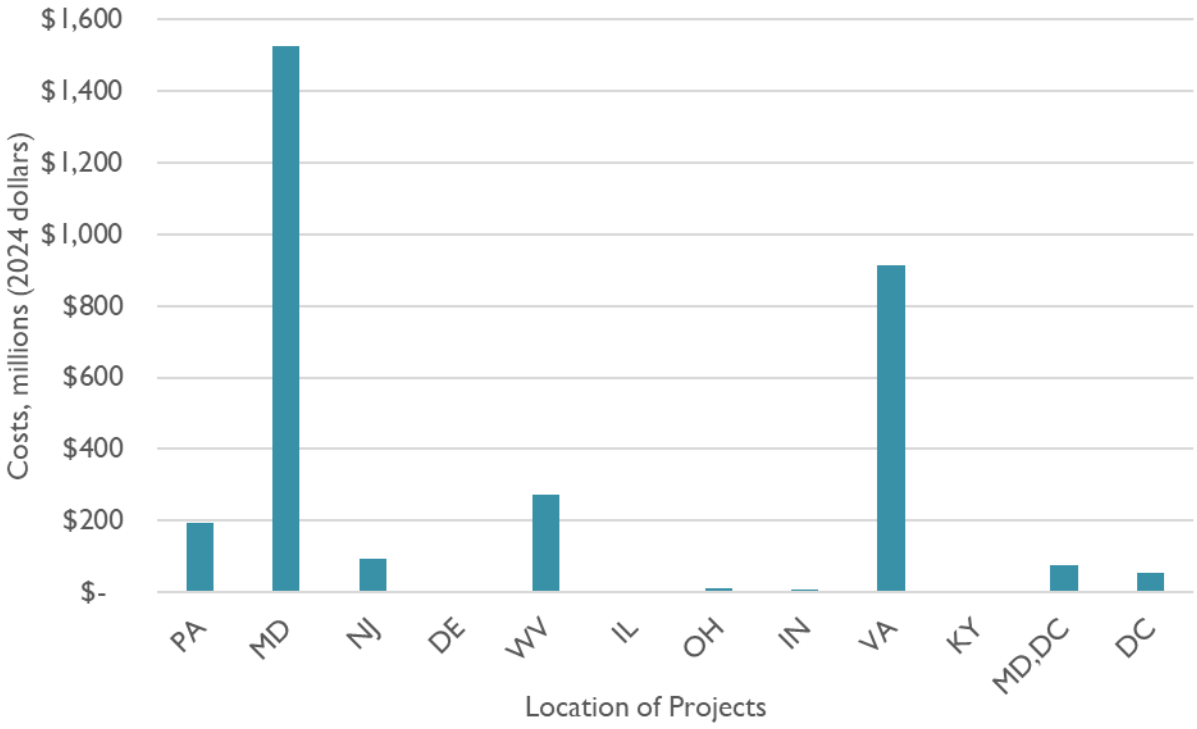
Notes: PJM plans the transmission system through the RTEP process based on a 5-year horizon; the years after 2030 are therefore unlikely to be complete. Figure does not include canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

2.2. Cost Allocation Approach

Transmission Enhancement Charges recover the costs of Baseline projects approved through PJM's RTEP in support of regional reliability. These costs are often allocated to multiple transmission zones or states. This means that the District benefits from, and is thus paying for, baseline transmission projects built throughout the PJM footprint. Both DC and Maryland electricity customers pay for projects allocated to the Pepco zone because the Pepco transmission zone includes both the District and parts of Maryland. This makes active engagement in PJM's planning and project oversight critical for managing transmission cost while advancing the District's clean energy goals and maintaining reliability.

Most baseline projects allocated to the Pepco transmission zone are located in Maryland, Virginia, and West Virginia (Figure 9). There is only one baseline transmission project located within the District.

Figure 9. Total baseline project costs that are allocated to the Pepco transmission zone, by their location (state), for projects with expected online dates from 2005 to 2032



Notes: Figure does not include canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

In principle, baseline projects are paid for by the transmission zones that benefit directly from the project or transmission asset. However, this cost allocation calculation can be complex and often contested.

Some projects solely benefit the customers within the transmission zone in which they are located. In these cases, that zone will take on 100 percent of the project costs (known as "direct allocation"). Of baseline project costs allocated to the Pepco transmission zone, 14 percent fall into this category and are paid for entirely by the Pepco zone. This portion amounts to $440 million (2024 dollars).

For projects that cross multiple transmission zones or have benefits that span multiple zones, costs may be allocated to different transmission zones using one of three approaches:

- Load ratio share: Costs are divided among the benefiting zones based on each zone's non-coincident peak demand (i.e., the maximum amount of power delivered to that zone).
- Distribution factor analysis: Costs are allocated according to the estimated contribution that each customer zone makes to power flows over the facility. This approach is typically used for alternating current (AC) facilities below 500 kV with budgets of at least $5 million.
- State agreement approach: One or more states may voluntarily agree to fund all or part of a project to achieve policy objectives.

Sixty percent of baseline projects that have costs allocated to the Pepco zone also have part of their costs allocated to other zones across the region. No state agreement approach project costs have been allocated to the Pepco transmission zone to date.

In simple terms, transmission costs are shared by the zones that benefit from those projects (e.g., receive power through new lines). However, in practice this approach is not always considered fair. The Maryland Office of People's Counsel (OPC) and other stakeholders have raised concerns about these cost allocation approaches in the context of recent transmission projects. For instance, the Maryland OPC filed comments pushing back against the cost allocation methods for millions of dollars of new transmission projects, almost exclusively due to data center growth in Virginia.[19] Customers in Pepco and neighboring BGE zones are allocated a large share of these project costs, despite experiencing relatively little load growth over the same period.[20] The OPC argues that this is unlawful and against the foundational ratemaking principals of cost allocation based on cost causation.[21]

[19] Maryland Office of People's Counsel. *Comments of the Maryland Office of People's Counsel, PJM Interconnection, LLC, Docket No. ER25-1811-000.* April 28, 2025. PDF. Available at: https://opc.maryland.gov/Portals/0/MPC%20Cmts%20ER251811%20%5BFinal%5D.pdf?ver=H7cwqPmI1rIghTavBZf1JA%3d%3d.

[20] Maryland Office of People's Counsel. "PJM Proposal Would Unlawfully Saddle Maryland Customers with Nearly $800 Million for Out-of-State Data Center Growth, OPC Tells Federal Regulators." Press release, April 28, 2025. Available at: https://content.govdelivery.com/accounts/MDOPC/bulletins/3de09c.

[21] Ibid.

PJM administers the FERC-approved TEC to each of the transmission zones or Transmission Owners responsible for these costs. The Transmission Owner will then pass on these charges to the load-serving entities (LSE) in its service territory, such as the Exelon distribution company or a retail competitive supplier. Pepco embeds a portion of its TEC into its zonal NITS rate; the Pepco zone's share of the baseline projects that it owns and operates.[22] Customers in the Pepco zone pay the Pepco NITS rate in addition to TECs from other Transmission Owners and zones.[23] The TEC is applied as a monthly rate to an LSE's monthly MW total in a zone. In other words, costs are allocated to the LSE based on each LSE's contribution to the zone's monthly peak demand. In the Pepco zone, DC represents 34 percent of total peak demand in the zone[24] and thus is responsible for about 34 percent of Pepco's baseline project costs. The Maryland portion of the Pepco transmission zone pays for the remainder.

Pepco includes these charges as part of the Supply Charges on its utility bills, both for customers using the default service (SOS) and for those using competitive retail suppliers. (Section 1.5, above, describes this process).

2.3. Cost Drivers for Projects Allocated to DC

While baseline transmission projects are broadly built to meet regional reliability needs, each project will have its own set of specific drivers. There are six key baseline transmission project drivers: (1) baseline load growth deliverability and reliability, (2) generator deactivation, (3) operational performance, (4) transmission owner criteria violation, (5) congestion relief, and (6) public policy. Table 1 below describes each of these. Baseline load growth projects represent the majority of project costs allocated to the Pepco transmission zone (Table 1).

[22] Pepco. December 11 ,2020. FC1017 Retail Transmission Rates. DC Public Service Commission, Formal Case 1017. Available at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=110342&guidFileName=583860b0-d760-41ee-897d-0618ea6dcf17.pdf.

[23] David Gardner and Associates. February 2024. Consumer Advocates of the PJM States' Transmission Handbook, Volume VI: Transmission Project Costs and Charges. Available at: https://www.dgardiner.com/wp-content/uploads/2024/03/DGA-CAPS_Transmission-Handbook-Vol-6.pdf.

[24] Potomac Electric Power Company District of Columbia Formal Case No. 1017, Response to DCG Data Request No.2. September 22, 2025.

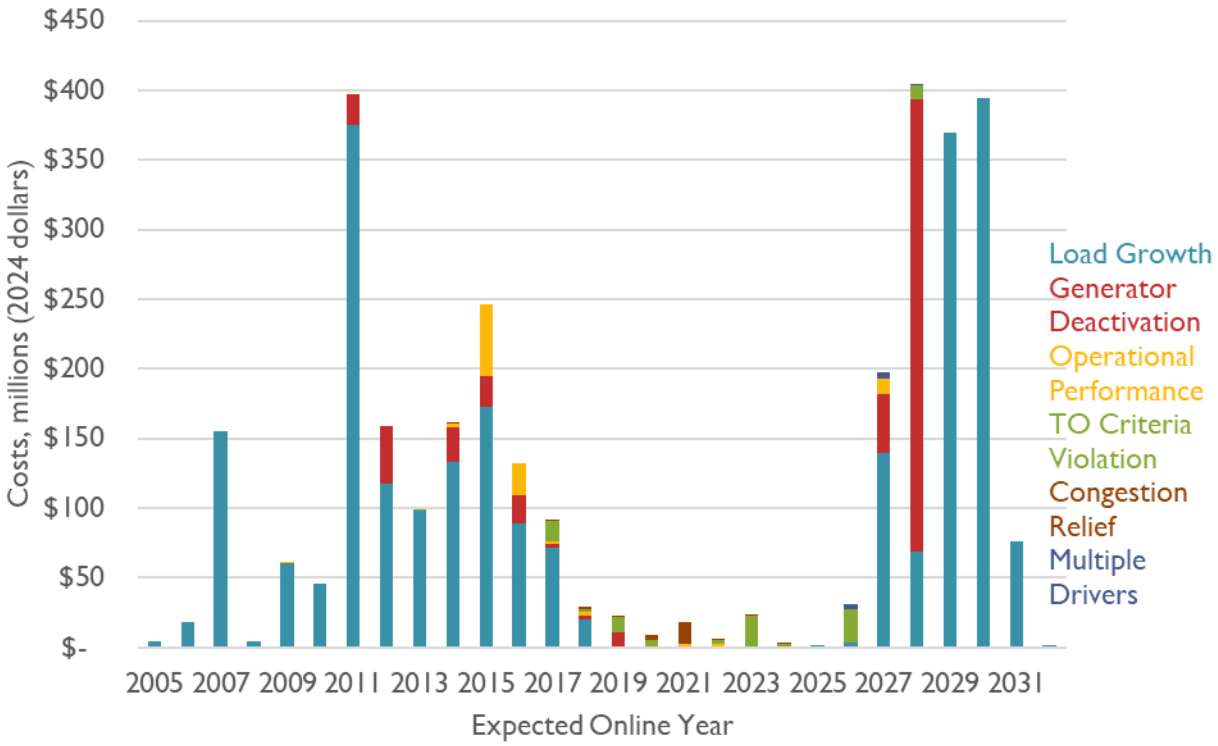
Table 1. Baseline transmission projects allocated to the Pepco transmission zone

Driver	Definition	Baseline Costs Allocated to the Pepco zone (millions, 2024 dollars)	% of Pepco Zone Baseline Transmission Costs
Baseline Load Growth & Reliability	Projects needed to maintain compliance with NERC, PJM, and Transmission Owner reliability standards under forecasted system conditions. Includes addressing load growth, thermal/voltage violations, short-circuit issues, and deliverability of resources to load.	$2,422	77%
Generator Deactivation	Projects triggered by the planned retirement of generation resources that would otherwise leave the system unable to meet reliability or deliverability requirements.	$515	16%
Operational Performance	Reinforcements that improve system operations or address deficiencies revealed in system performance studies. May include voltage support, dynamic stability, transfer capability, or operational flexibility to maintain reliability.	$98	3%
Transmission Owner Criteria Violation	Upgrades required to satisfy more stringent local reliability standards filed in each Transmission Owner's FERC Form 715 (beyond PJM's minimum criteria).	$95	3%
Congestion Relief	Projects justified because they reduce congestion and lower overall system production costs. These are identified through PJM's Market Efficiency analysis.	$26	1%
Public Policy	Projects driven by federal, state, or local policy requirements, such as renewable portfolio standards or state-initiated transmission needs. Under PJM's framework, these may be advanced through the State Agreement Approach.	$0	0%
Multiple drivers	More than one of the six drivers above.	$9	<1%

Notes: Table does not include canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

The influence of these drivers on project spending fluctuates over time, although baseline load growth projects are consistently the key project driver for both in-service/historical projects and approved projects that will be built in the coming years (Figure 10).

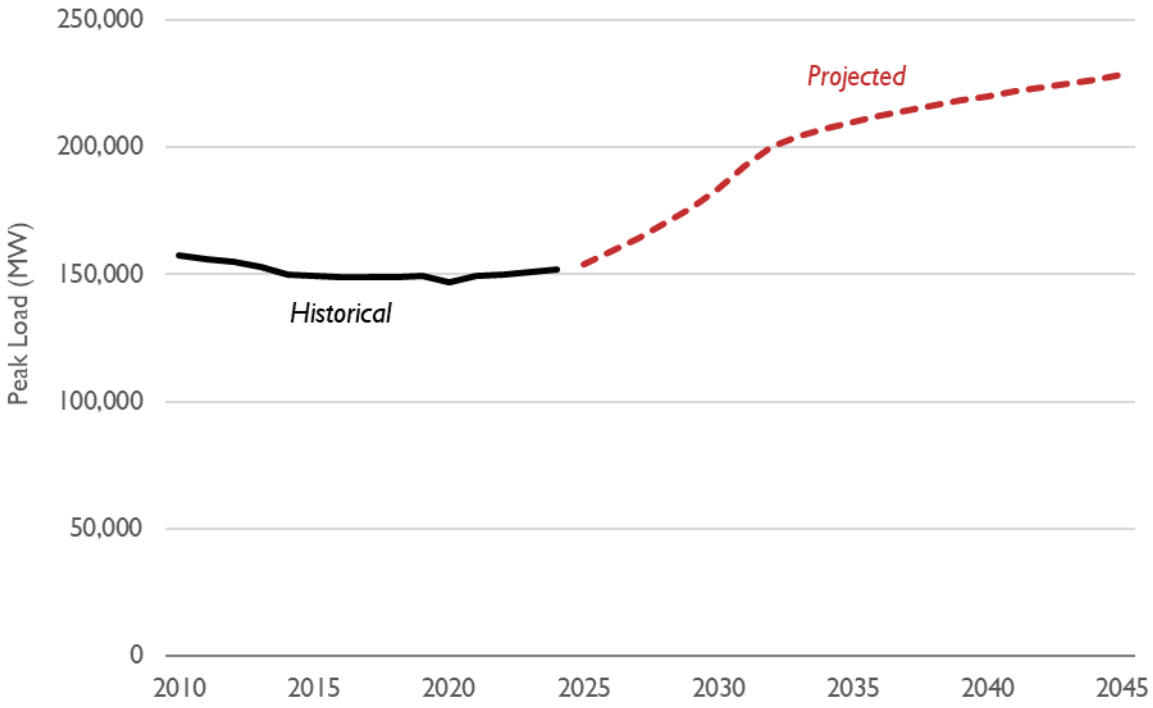
Figure 10. Baseline transmission projects allocated to the Pepco transmission zone, by driver type and expected online year



Notes: PJM plans the transmission system through the RTEP process based on a 5-year horizon; the years after 2030 are therefore unlikely to be complete. Figure does not include canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

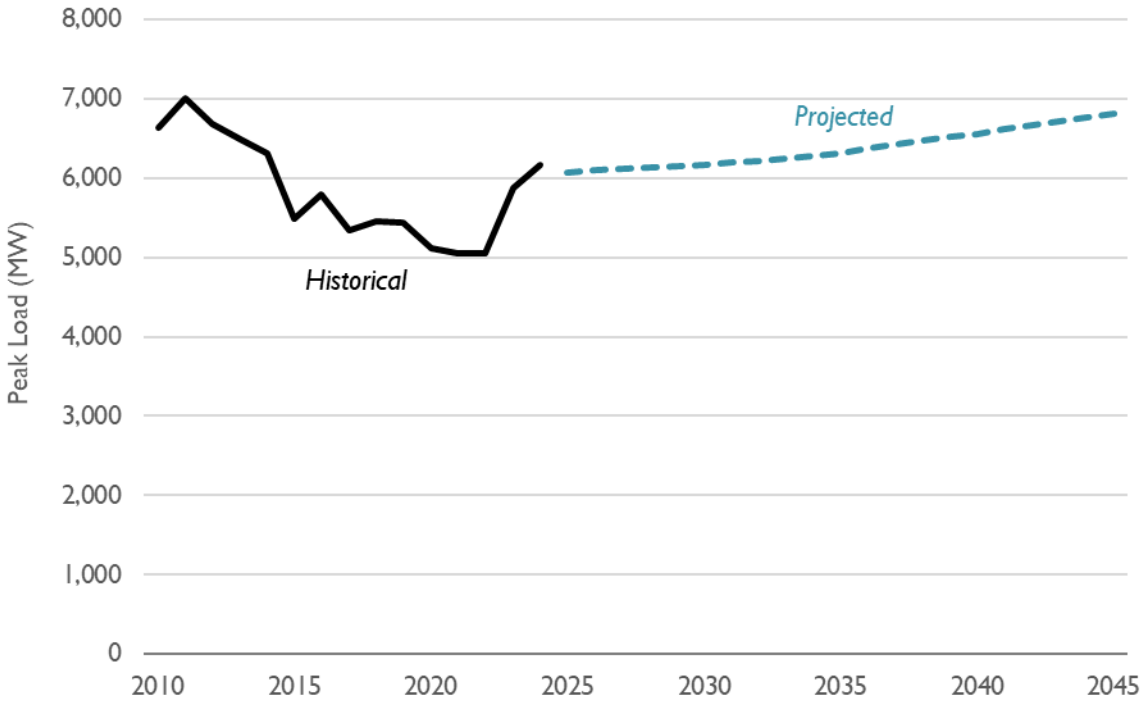
PJM is projecting that RTO-wide peak load will increase substantially in the coming years, largely due to data center load growth in Virginia and elsewhere in the mid-Atlantic (Figure 11). PJM is projecting that Pepco's load will grow by only 4 percent from 2025 to 2045, while it is projecting the RTO-wide load to increase by 48 percent over the same time period (Figure 12). As a result, load growth outside of DC and the Pepco zone is likely to continue to drive more and more transmission project spending, at an accelerating pace moving forward, some of which will likely be allocated to the Pepco zone.

Figure 11. PJM RTO historical and projected load



Source: PJM 2025 Load Forecast. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

Figure 12. Pepco zone historical and projected load



Source: PJM 2025 Load Forecast. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process; EIA 861, "Operational Data."

Generator deactivations (power plant retirements) have also been a growing project driver for recently approved baseline transmission projects. Generator deactivation projects are often built to eliminate the need for reliability-must-run (RMR) arrangements by bringing in replacement energy from another area. An RMR service refers to a generating unit that would otherwise retire but that PJM has requested stay online to maintain grid reliability. Examples in the region include the current RMR arrangements for Brandon Shores and Wagner (located in Maryland in the BGE zone) and recently terminated Indian River RMR (located in Delaware in the DPL-South zone). Transmission projects addressing these RMRs have been allocated in part to the Pepco transmission zone. Furthermore, projects that address generator deactivations typically cost substantially more than other transmission project types, including baseline load growth projects.

2.4. Case Study: Brandon Shores Deactivation Project

Project Overview

The Brandon Shores coal-fired power plant, located in the BGE transmission zone in Maryland, was scheduled to deactivate on June 1, 2025. PJM requested Brandon Shores to remain in operation through an RMR contract. To enable the plant's eventual retirement and maintain grid reliability in the region,

PJM determined that several transmission upgrades were needed to import replacement energy into the zone. PJM's analysis of the retirement found issues with several criteria: Load Deliverability, Generator Deliverability, and N-1-1 Contingencies (voltage violation). To address these issues, PJM proposed $780 million of new transmission assets,[25] including two new high voltage (530 kV and 230 kV) transmission lines, three new high voltage substations, two new substation expansions, and several voltage support technologies.[26] Nearly a quarter of these project costs are allocated to the Pepco transmission zone.

PJM deemed these immediate need projects, and so they were procured outside of the competitive process for baseline projects. Over 70 percent of the project costs are for projects owned by BGE, while 15 percent belong to Pepco. PECO, Transource, and APS are responsible for the remaining 14 percent. The projects owned and operated by Pepco have costs that are allocated to both the Pepco transmission zone and other zones in the region.

To maintain grid stability, Units 1 and 2 of Brandon Shores will continue to operate beyond the planned deactivation date of June 1, 2025, under an RMR agreement until May 31, 2029, when the transmission solutions are expected to be fully online. The cost allocation for the RMR out-of-market expenses follow the same cost allocation as the Brandon Shores Deactivation Transmission Project.[27] As such, these costs are embedded into transmission rates [28] and thus into utility bills for customers in DC and the surrounding region.

The projected in-service date for most of these transmission projects is December 31, 2028, with some projects coming online in 2027.

Cost Estimates and Allocation

The total estimated costs for the Brandon Shores Deactivation Projects were originally $738.83 million but subsequently increased to $1.5 billion, reflecting a net increase of approximately $775.13 million.[29]

---

[25] Brandon Shores Deactivation Project includes baseline projects B3780 and B3781, which includes multiple sub-projects (e.g., B3780.10, B3780.11, B3780.12).

[26] GridLab. *Brandon Shores Retirement Analysis: January 2024*. GridLab, January 2024. https://gridlab.org/portfolio-item/brandon-shores-retirement-analysis-january-2024/.

[27] Synapse Energy Economics. August 2024. *Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland*. Prepared for the Maryland Office of People's Counsel. Available at: https://www.synapse-energy.com/sites/default/files/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-13%208-29-24%2023-067.pdf.

[28] Lynch, J. November 9, 2023. *Overview of Compensation Mechanisms and Cost Allocation for Reliability Must Run (RMR) Units.* Deactivation Enhancements Senior Task Force, PJM Interconnection. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/destf/2023/20231109/20231109-item-02---rate-mechanisms-and-cost-allocation-of-rmr-units.pdf.

[29] McGovern, Jason. "PJM Board Approves New Transmission Projects To Support Grid Reliability." *PJM Inside Lines*, February 26, 2025. https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

The significant cost increase[30] is due to higher vendor quotes, detailed design changes, and increased labor and material costs, but the scope of the project itself has not changed.[31]

Multiple transmission zones, including the Pepco zone, will benefit from these transmission upgrades that will enable Brandon Shores to retire. The Pepco zone is responsible for roughly 23 percent of these costs, or $369 million.

PJM Process

In early April of 2023, the owner of Brandon Shores announced its intent to retire the plant. PJM subsequently conducted a reliability analysis and identified reliability violations that would result from the generator's deactivation. On June 6, 2023, PJM presented the Brandon Shores Deactivation Projects at the TEAC, outlining the expected thermal and voltage violations from the planned plant retirement and detailed the proposed 500 kV and 230 kV reinforcements needed to maintain reliability. Since these are immediate needs solutions, PJM announced the projects were all assigned to incumbent Transmission Owners (BGE and Pepco, among others). At a July 11, 2023, TEAC meeting, PJM again presented for stakeholder discussion the grid violations associated with the deactivation, the proposed solutions, and the estimated costs. The following day, the PJM Board approved the PJM staff-recommended Brandon Shores Deactivation Projects for inclusion in PJM's RTEP Baseline Projects.[32] On February 4, 2025, PJM staff provided updates to the TEAC showing major revisions to these projects costs, which nearly doubled (due to the availability of more detailed engineering and vendor quotes). At the end of February, the PJM Board approved the increased project costs.[33] Separately, state utility regulatory commissions also reviewed and approved Transmission Owner projects at the local level, often through dockets for approval of Certificates of Public Convenience and Necessity (CPCN), which were needed to build the identified transmission upgrades.

During this process, multiple stakeholders raised extensive concerns about the projects, focusing primarily on the scale of cost escalation, the risk of project delays, and the lack of transparency and effective stakeholder engagement.[34]

---

[30] Specifically, for one project B3780.11.

[31] Abdulsalam, Sami. *Reliability Analysis Update*. Transmission Expansion Advisory Committee, PJM Interconnection, February 4, 2025. https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250204/20250204-item-12---reliability-analysis-update.pdf.

[32] PJM Staff White Paper. July 2023. Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board. PJM Interconnection. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230711/20230711-pjm-teac-board-whitepaper-july-2023-public.ashx.

[33] PJM Inside Lines. February 26, 2025. PJM Board Approves New Transmission Projects To Support Grid Reliability. Available at: https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

[34] Protest of the Maryland Office of People's Counsel. September 13, 2023. Docket Nos ER23-2612-000, ER23-2612-001. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/Final%20Md%20OPC%20Protest%20ER23-2612%20PJM%20RTEP%20Baseline%20filing.pdf?ver=tgen2T7bSdTQSH44n1SQ6A%3d%3d.

3. SUPPLEMENTAL TRANSMISSION PROJECTS

Supplemental transmission projects are enhancements and expansions that address local reliability needs. These projects are planned and developed by Transmission Owners. They are exempt from PJM's competitive bidding process and are not subject to planning and project oversight review by the PJM Board. PJM's only role in regard to these projects is to evaluate the proposed project's reliability impact on the region's grid, but not whether the project is needed or prudent.

Supplemental projects have been a major driver of transmission cost increases across PJM. They represent roughly 30 percent of transmission costs allocated to the Pepco zone. Increased spending on transmission projects could be a cause for concern as it may lead to large increases in customers' bills, particularly as the region builds other new transmission projects to connect new sources of generation and meet growing demand.

3.1. Planning and Oversight Process

Although PJM applies consistent policies for developing RTEP projects, the process for planning supplemental projects can look different depending on the state or utility service territory in question. In the District, Pepco is the transmission owner responsible for advancing these projects through PJM's stakeholder framework. Under Attachment M-3 of PJM's Open Access Transmission Tariff (OATT), Pepco must present supplemental projects at or above 230 kV to the TEAC, while projects below 230 kV are reviewed through the relevant Subregional RTEP Committee. In DC's case, these projects are reviewed by the Mid-Atlantic Subregional Committee. Stakeholders in the District can provide feedback during these meetings, which typically include an Assumptions Meeting, a Needs Meeting, and a Solutions Meeting (referred to as the M3 process). For DC advocates and customers, these forums are often the main venue to weigh in on Pepco's proposed projects. However, current rules do not require Pepco to change or adjust its plans in response to stakeholder comments. Stakeholders may also file a complaint at FERC once the project has completed the M3 process at PJM.

Because of the lack of rigorous oversight, stakeholders, including those in DC, have fewer opportunities to challenge the prudency of these projects, compared to the RTEP process for baseline projects. The impact and implications on DC customers could be large and could push electricity costs higher over time. Oversight reforms in other regions (e.g., ISO-NE's Independent Transmission Monitor) could be a model for PJM.

Supplemental projects for Pepco in DC continue to work their way through the M3 process. For example, on September 9, 2025, Pepco presented on a $590 million transmission project at a Solutions Meeting of the TEAC.[35] The project is intended to address needs associated with aging infrastructure.

3.2. Cost Allocation Approach

NITS charges are the mechanism used to recover the costs of Supplemental Projects. NITS are calculated based on the annual revenue requirement of the Transmission Owner, including its rate of return (ROR). FERC has authorizes the Transmission Owners to make the ROR in exchange for owning and maintaining transmission lines and allowing customers to take electric service over the lines.[36] Pepco embeds a portion of its TEC into its zonal NITS rate; it includes the Pepco zone's share of the baseline projects that it owns and operates.[37]

Transmission Owners charge their customers (e.g., LSEs) within their zone a monthly demand charge based on the LSE's peak load contribution and the Transmission Owner's NITS.[38]

Once the LSE's have been charged (e.g., Pepco or a competitive retail supplier), they then pass these costs onto their customers through charges included within the supply side of a customer's bill (see Section 1.5, above, for a description of this process).

3.3. Cost Drivers for Projects Allocated to DC

Transmission Owners propose supplemental projects according to five key drivers: (1) customer service; (2) equipment material condition, performance, and risk; (3) operational flexibility and efficiency; (4) infrastructure resilience; and a catchall category of (5) other. These are described in Table 2 below. Customer-service-type projects dominate supplemental projects owned and operated by Pepco in its role as a Transmission Owner. Across the overall PJM footprint, the second category of equipment material condition, performance, and risk represent the majority of project costs, closely followed by projects with multiple drivers and customer-service-type projects (Table 2).

---

[35] Exelon. September 9, 2025. Transmission Expansion Advisory Committee, PEPCO Supplemental Projects. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250909/20250909-item-11---pepco-supplemental-projects.pdf.

[36] David Gardiner and Associates (DGA). *Consumer Advocates of the PJM States' Transmission Handbook, Volume VI: Transmission Project Costs and Charges*. CAPS. February 2024. https://www.dgardiner.com/wp-content/uploads/2024/03/DGA-CAPS_Transmission-Handbook-Vol-6.pdf.

[37] Pepco. December 11 ,2020. FC1017 Retail Transmission Rates. DC Public Service Commission, Formal Case 1017. Available at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=110342&guidFileName=583860b0-d760-41ee-897d-0618ea6dcf17.pdf.

[38] Some Transmission Owners, including Pepco, embedded their own TEC charges allocated to their own zone in their NITS rates. However, the NITS rate does not include TEC charges from other Transmission Owners.

Table 2. Supplemental transmission projects located within the Pepco transmission zone

Driver	Definition	Pepco Supplemental Project Costs (millions, 2024 dollars)	% of Pepco Supplemental Project Costs	% of PJM-Wide Supplemental Costs
Customer Service	Service to new and existing customers; Interconnect new customer load; address customer transmission and distribution load growth, outage exposure, and equipment loading	$1,183	79%	23%
Equipment Material Condition, Performance and Risk	Degraded equipment performance, material condition, obsolescence; equipment failure; employee and public safety; and environmental impact	$245	16%	38%
Operational Flexibility and Efficiency	Optimizing system configuration, equipment duty cycles and restoration capability; minimize outages	$25	2%	14%
Infrastructure resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potential disruptive event (including severe weather, geo-magnetic disturbances, and physical and cyber security challenges)	$0	0%	3%
Other	Meet objectives not included in other definitions including: industry recommendations, potential generation retirements, technology pilot projects, governmental/utility commission regulation, and state policy goals	$4	<1%	1%
Multiple drivers	More than one of the five drivers above	$45	3%	21%

Notes: Table does not include canceled, on-hold, and withdrawn projects Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

Not only do customer-service type projects represent a large share of Pepco supplemental projects, they also have the highest average project cost size, increasing from $16 million in 2017, to $203 million in

2018, $227 million in 2024, and $685 million in 2025.[39] Table 3 shows the average costs of Pepco's supplemental projects compared to PJM-wide average supplemental project costs.

Table 3. Average project costs for supplemental transmission projects located in the Pepco transmission zone, by driver type, relative to the PJM-wide average

Driver	Average Pepco project costs (millions, 2024 dollars)	Average PJM-wide project costs (millions, 2024 dollars)
Customer Service	$236.7	$11.7
Equipment Material Condition, Performance and Risk	$7.4	$11.5
Operational Flexibility and Efficiency	$5.1	$14.9
Infrastructure resilience	-	$28.3
Other	$4.1	$13.1
Multiple Drivers	$44.9	$10.7
Total	**$33.4**	**$12**

Notes: Table does not include canceled, on-hold, and withdrawn projects. Data is sourced from PJM's Project Status & Cost Allocation dataset and was downloaded by Synapse in August 2025. Available at: https://www.pjm.com/planning/m/project-construction.

3.4. Supplemental Project Case Study

Pepco's Capital Grid Project aims to enhance grid reliability and meet growing demand in the DC area. The project involved construction of a new Mt. Vernon Substation, upgrades to several other existing substations and associated infrastructure.[40] Pepco identified multiple drivers for the project: (1) addressing predicted substation overloads in the DC area, (2) replacing aging infrastructure and increasing system performance, and (3) increasing reliability to critical load by transforming the radial supply system to a networked configuration.

The project also includes upgrades to Pepco's distribution grid, which fall outside the PJM transmission process. Pepco has stated that the Capital Grid Project in total represents a "$1.6 billion investment in the future of energy in Washington, D.C."[41]

The project was first presented to the Mid-Atlantic subregional RTEP Committee over 10 years ago, where the scope and new costs were also discussed. For Supplemental Project S0839, a major

[39] Years are expected in-service years.

[40] PJM Interconnection. *SRRTEP Mid-Atlantic Reliability Analysis Update*. December 8, 2015. https://www.pjm.com/-/media/DotCom/committees-groups/committees/srrtep-ma/20151208/20151208-reliability-analysis-update.pdf.

[41] Electric Perspectives podcast. July 16, 2025. "Delivering a Reliable, Secure, and Affordable Energy Future With Pepco Holdings President and CEO Tyler Anthony." Available at: https://www.electricperspectives.com/podcast-tyler-anthony-pepco/.

component of the Capital Grid Project, the originally proposed in-service date was December 31, 2021, followed by a revised in-service date of June 30, 2021.[42] However, it is now expected to be online by the end of September 2025, according to PJM's Transmission Cost Planner.[43]

The originally proposed project cost for Supplement Project S0839 was $345 million (2015 dollars). Pepco later revised this figure to $337 million (2015 dollars), following a change in scope. This equates to $685 million in today's dollars. Pepco's customers pay for the entirety of this project, with roughly 34 percent paid for by DC customers specifically.[44]

As noted above, the Capital Grid Project also includes companion distribution system assets, including lower voltage substation equipment and distribution feeder lines. The PSC has oversight over the distribution system elements of this project through Formal Case No 1144, where Pepco, stakeholders, and other members of the public have provided input on Pepco's proposal for upgrades associated with the Capital Grid Project.

4. NETWORK UPGRADES

Network upgrades are transmission infrastructure upgrades needed to support interconnection of new generators, merchant transmission facilities looking to interconnect to the network, or new transmission requests in an area with insufficient transmission capacity. Network upgrades are planned through the interconnection queue process, including through studies PJM conducts to determine upgrades that are needed to interconnect a new generator. Network upgrades for new generation interconnection are covered by project developers, who integrate related costs into their market offer prices. Transmission Owners seeking to interconnect also pay for their network upgrades. Network costs are rising due to the increasing cost of interconnection. Project developers pay for network upgrade costs and integrate that cost into generation prices, thereby indirectly increasing consumer costs. In PJM, network upgrades represent 10 percent of total transmission costs, while in the Pepco transmission zone they represent less than 1 percent of total costs.

PJM is having major issues with its clogged interconnection queue, which raises resource adequacy concerns. As data centers push load projections to unprecedented levels at an alarming pace, and as old, inefficient generators continue to retire, the system needs more generation to come online quickly. Although PJM is making efforts to reform its interconnection queue process, it is still slow and expensive

[42] PJM Interconnection. *SRRTEP Mid-Atlantic Reliability Analysis Update*. December 8, 2015. https://www.pjm.com/-/media/DotCom/committees-groups/committees/srrtep-ma/20151208/20151208-reliability-analysis-update.pdf.

[43] PJM Interconnection. Project Status & Cost Allocation: Transmission Cost Planner. Available at: https://www.pjm.com/planning/m/project-construction.

[44] Based on DC's contribution to the zonal peak load. Potomac Electric Power Company District of Columbia Formal Case No. 1017, Response to DCG Data Request No.2. September 22, 2025.

for resources looking to interconnect and come online. The increasing network costs only add to these challenges. Incorporating more advanced transmission technologies could help improve interconnection costs and timelines.

5. RECOMMENDATIONS

Cost increases are expected to continue rising in the near term and exacerbate current concerns about affordability in the District. There are multiple avenues for state agencies, advocates, and other stakeholders to help address these concerns:

- **Improve PJM load forecasting, especially around data center loads.** Given that data centers are the main driver of projected load growth in PJM, and by extension, transmission planning, it is critical that the large load adjustments that PJM includes in its load forecasts are realistic, based on best available data, and well-vetted. Increased transparency, oversight, and better data is needed to improve the accuracy of PJM's data center load forecasts. Improved regional collaboration around data gathering can reduce the potential for double-counting of data center loads across jurisdictions.

- **Increase oversight and control cost escalation for transmission projects.** Cost increases associated with supplemental projects and immediate needs projects can present concerns from a ratepayer perspective. Establishing an independent organization analogous to a Market Monitor to review, and where necessary, challenge prudency of costs associated with these projects could be valuable. Similar oversight organizations are currently under consideration in ISO New England. Consumer Advocates in New England are advancing initiatives to standardize the transmission project review process, particularly for asset condition projects (akin to supplemental projects in PJM); this would require Transmission Owners to submit a benefit-cost analysis and include considerations of rightsizing to accommodate future electrification and other system changes.

- **Participate actively in PJM and FERC transmission proceedings.** Transmission projects, cost allocation methodologies, and planning processes are developed and vetted in several important PJM committees and FERC proceedings. DC agencies could consider increasing their participation in these—for example, in the PJM TEAC, the M3 process, and the Independent State Agencies Committee (ISAC) to provide input into the need for and costs of various transmission projects, including supplemental projects.

- **Improve multi-state coordination** to address rising transmission costs in the region. This could include addressing baseline project cost allocation approaches and/or the prudence of supplemental projects. States could also coordinate on other policies and initiatives such as effective implementation of FERC Order 1920, which could help improve transparency, cost allocation, and incorporation of alternative transmission technologies (ATT) and grid enhancing technologies (GETs), among other features of long-term transmission planning.