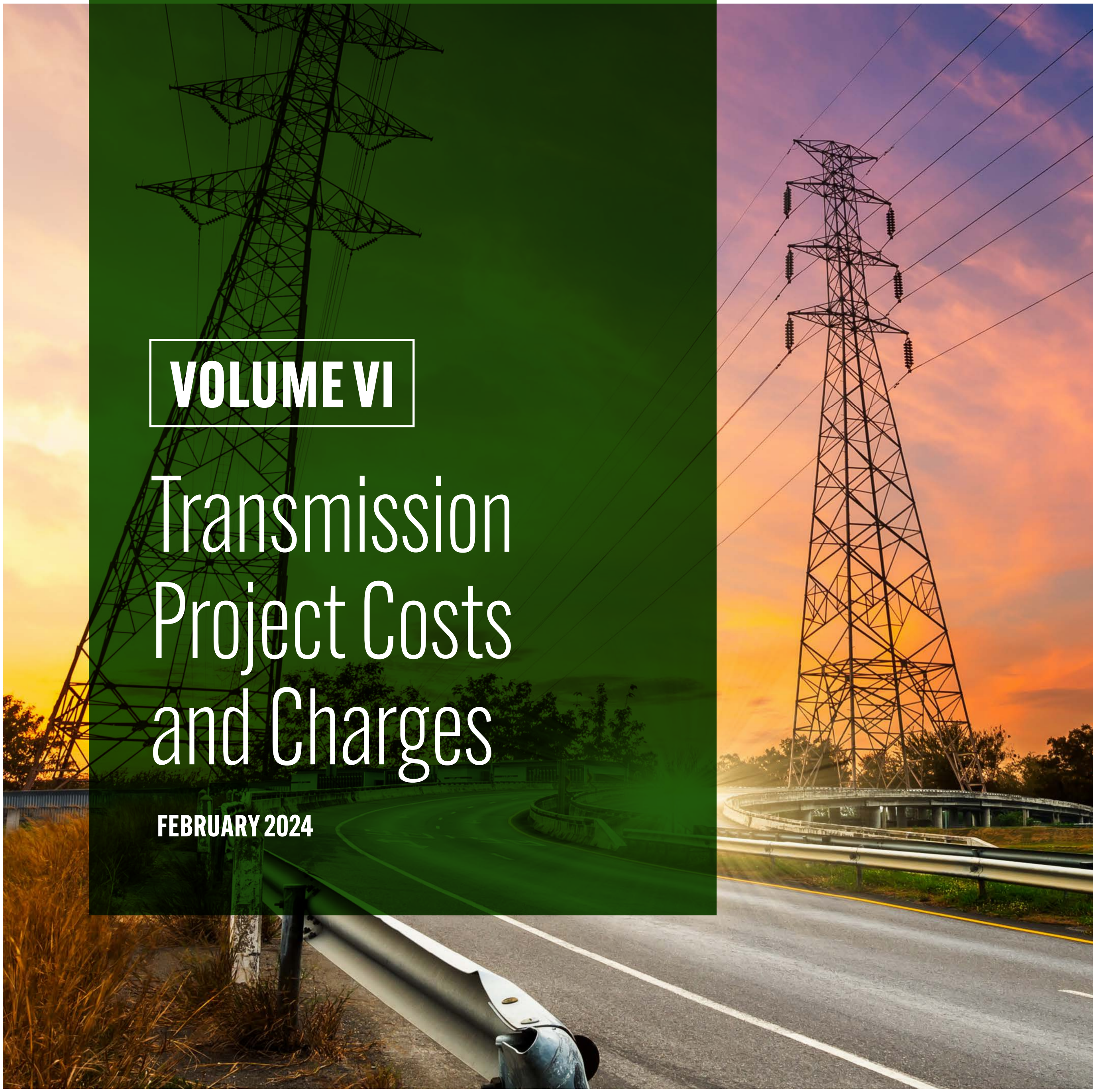


VOLUME VI

Transmission Project Costs and Charges

FEBRUARY 2024

CONSUMER ADVOCATES OF THE PJM STATES'
TRANSMISSION HANDBOOK

D|G/A
David Gardiner and Associates

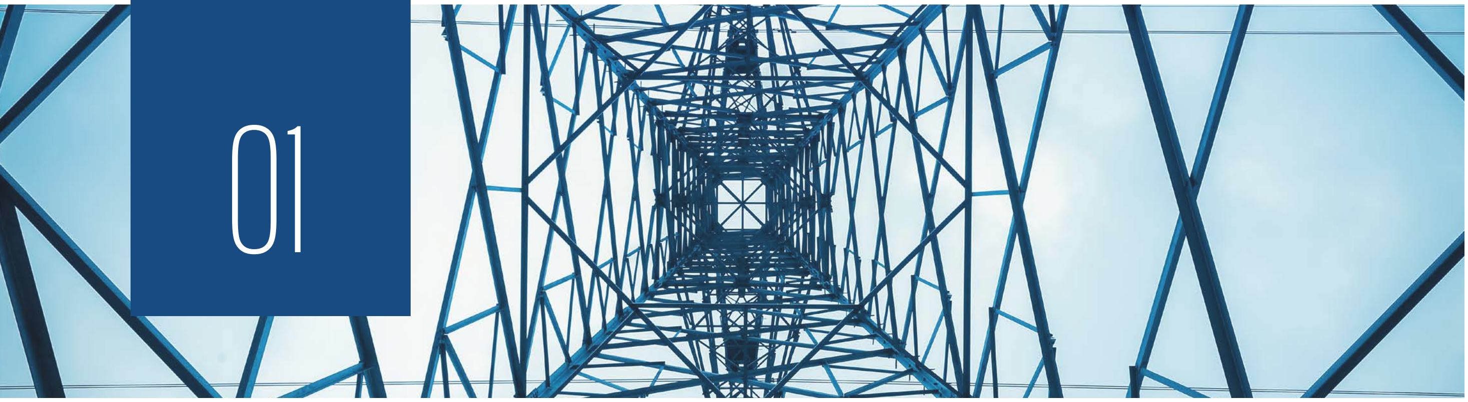
INTRODUCTION

The Consumer Advocates of the PJM States (CAPS) commissioned this guide to help consumers, their advocates, and others better understand how transmission is developed and paid for in the PJM region. Read the executive summary in Handbook Volume I to learn more about PJM and CAPS.

Handbook Volume VI explores:

- the different types of transmission service available to PJM customers and how PJM collects payments for the development and use of transmission lines;
- the processes for determining which customers are responsible for transmission project construction costs;
- network Integration Transmission Service (NITS) rates and transmission enhancement charges, including how they are calculated, how they have changed over time, and where advocates can find more information about these rates and charges; and
- additional transmission-related charges that may appear on a transmission customer's bill.

Table of Contents



01

Overview of PJM Transmission Costs

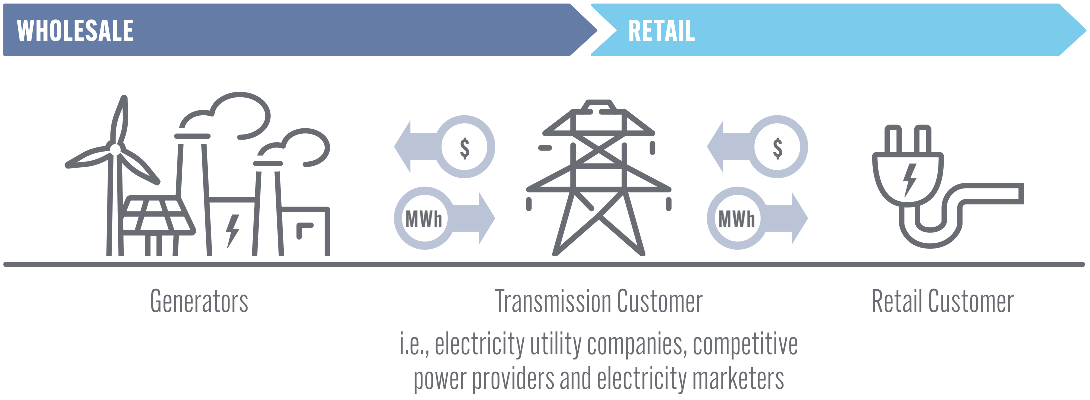
A. Who pays for electric transmission?

Customers who consume energy—such as residential and commercial energy users—ultimately fund the construction, operation, and maintenance of transmission lines, but these ***end-use*** *customers* do not pay PJM directly for transmission costs. Instead, a go-between entity—such as a municipal distribution utility or rural electric coop (also known as load-serving entities)—obtains transmission service from PJM to transport power over the lines and then resells the electricity to end-use customers. In the regulatory world, the entities that buy and resell power are also referred to as ***wholesale power*** *purchasers* or *wholesale customers*. Wholesale customers can also include third party power providers—who do not own or operate their own distribution systems, but in certain states are allowed to sell electricity to end-use customers. Additionally, large industrial users who get power delivered directly from a generator to their own private drop point can be a wholesale customer.

The wholesale customers are considered the transmission customer and are responsible for paying PJM for use of that service. Transmission customers may also include merchant transmission owners whose lines are interconnected to another transmission owner's line, but this handbook volume focuses largely on wholesale customers who take transmission service.

In paying their utility bills, end-use customers "reimburse" the wholesale customer for obtaining transmission service. (Handbook Volume III provides more information about end-use customer bills.)

FIGURE 1. Wholesale vs. Retail Electricity Sales



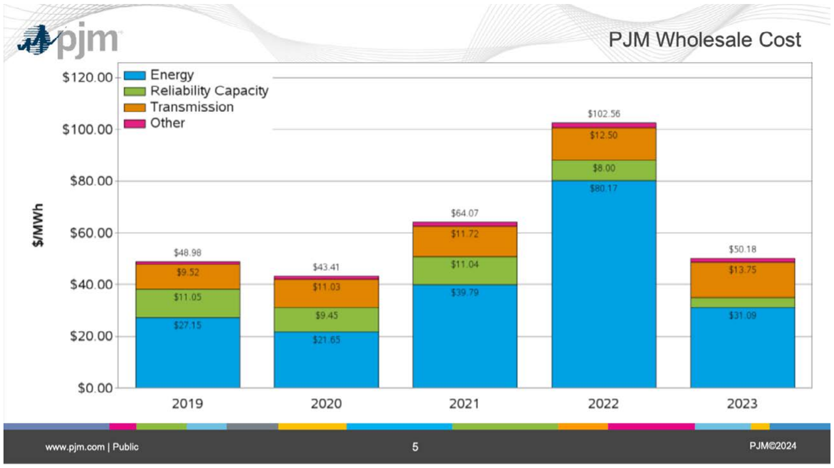
(Credit: FERC, "An Introductory Guide for Participation in PJM Processes," July 3, 2023).

B. What portion of a wholesale customer's PJM bill is attributable to transmission?

In addition to transmission charges, a wholesale customer's bill may include charges for the power they are purchasing to resell (energy charges), for ensuring there is enough generation available to meet the region's energy needs (reliability capacity), and for other charges such as administrative and ancillary services. The exact percentage of a wholesale customer's bill attributable to transmission depends on several factors including the transmission zone they are in, the type of transmission service they take, and the amount of power they move.

The disaggregated information can be difficult to calculate, but PJM does provide monthly reports to the Member's Committee on wholesale costs across the region. Figure 2 provides a snapshot of PJM's Market Report for December 2023 showing a comparison of average wholesale costs in dollars per megawatt hour ($/MWh) between 2019 and 2023, plus the portion attributable to each cost component (energy, transmission, capacity, and other). While energy continues to make up the highest percentage of regional wholesale costs, transmission service costs have been steadily rising over time, overtaking capacity costs as the second largest component of wholesale costs.

FIGURE 2. PJM Wholesale Cost 2019 - 2023 from PJM Presentations[1]



(Credit: PJM, "Markets Report," MC Webinar at slide 5, Jan 22, 2024).

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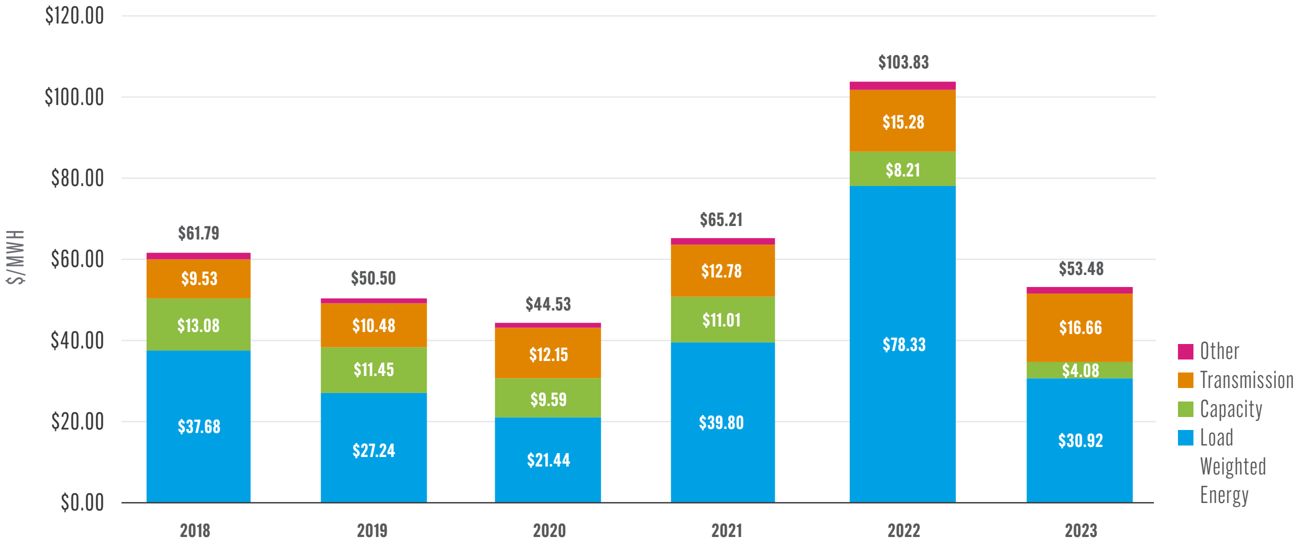
[1] Note that the monthly markets reports are accessible on PJM's Report's & Notices Webpage under Markets & Operations.

Figure 3 provides similar information about the average PJM wholesale costs for the last several years, but this chart is based on PJM Independent Market Monitor (IMM) reports. Though the IMM data is not identical to the calculations in PJM's chart, both PJM and the IMM report the same trend of rising transmission costs.

FIGURE 3. Wholesale Costs in PJM 2018 - 2023 based on Independent Market Monitor Data



(Source Data: Monitoring Analytics, "Data: Components of PJM Price, 2018-2023," last accessed Jan. 16, 2023).

C. What charges does PJM assess on wholesale customers that use the transmission network?

The two main sets of charges that PJM assesses on wholesale transmission customers are: ***transmission service charges*** and ***transmission enhancement charges***. They are collectively designed to reimburse transmission owners for the costs they incur to construct new and upgrade existing transmission lines and to maintain operational and reliable transmission infrastructure. As discussed in Handbook Volume IV, there are three categories of new/upgraded transmission projects in PJM—supplemental, regional, and network—with wholesale customers being responsible for supplemental and regional project costs.

Transmission service charges are based on the type of transmission service the wholesale customer receives. These charges incorporate transmission line operation and maintenance costs and costs incurred to build certain transmission projects. The costs for building and upgrading *supplemental* projects are incorporated into the *transmission service charge*.

Transmission enhancement charges reflect the transmission owners' costs for developing *regional* transmission projects that are planned and approved by the PJM board through PJM's Regional Transmission Expansion Plan (RTEP). In some transmission zones, the transmission enhancement charges assessed by PJM cover regional projects: (1) built by the incumbent transmission owner in that zone, and (2) built by other transmission owners where a portion of the project costs are allocated to that transmission zone. However, in some transmission zones, the transmission enhancement charges assessed by PJM cover only the second bucket of projects—those built by other transmission owners. In these cases, the incumbent transmission owner from that zone wraps its own transmission enhancement charges into its transmission service charge calculations.

The next few sections provide more details on transmission service and enhancement charges.

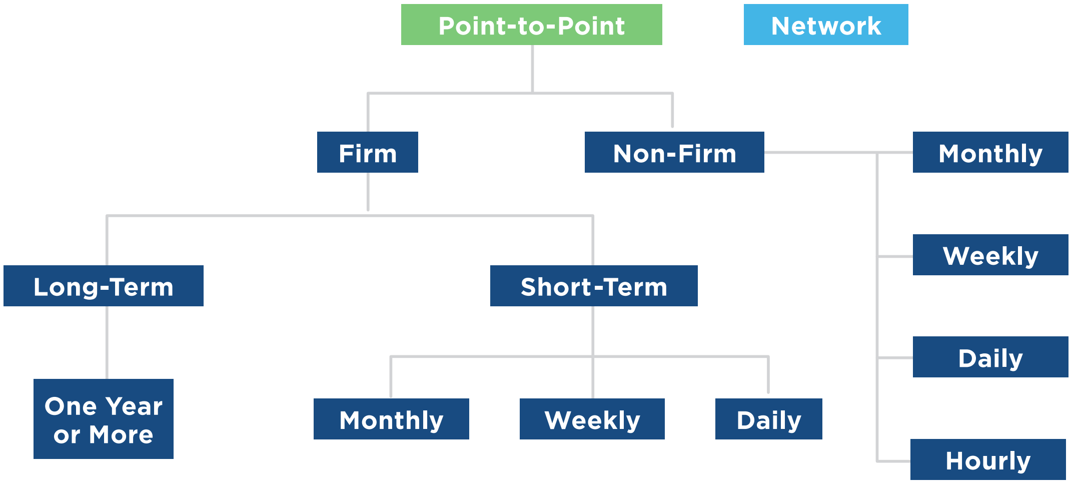
02

Transmission Service Charges

A. What are the different categories of transmission service available to wholesale customers?

PJM transmission customers may elect either **network service** or **point-to-point service**.

FIGURE 4. PJM Transmission Service Options



(Source: PJM, "Manual 2: Transmission Service Request," at Section 1.1, 2023).

B. What is network service?

The transmission resources within the PJM footprint are also known as the "PJM network" and the end use customers within PJM makeup the "network load." Transmission customers use **network service, also referred to as Network Integration Transmission Service,** to support their network loads (i.e. their retail customers). Specifically, they use network service to transmit:

(1) capacity and energy from resources located within, or deliverable to, the PJM network, and

(2) energy from the PJM energy market.[2]

C. What is point-to-point service?

Transmission customers use **point-to-point service** to transfer capacity and energy from a specific point of "receipt" to a point of "delivery." For example, a wholesale customer may use point-to-point service to deliver power from a generator in PJM to an end-use customer located outside PJM. There are two types of point-to-point service: *firm* and *non-firm.*

- Customers receiving firm point-to-point service pay to reserve capacity on a transmission line—simply put, they get priority to have the generation resources they need moved over the line.
- By contrast, customers receiving non-firm point-to-point service get access to transmission capacity when it is available "in excess" of what is needed to provide reliable service to native load customers, network customers, and others taking long-term and short-term firm point-to-point transmission service.[3] Customers receiving non-firm point-to-point service will be the first to have their transmission line access curtailed if the line is over-subscribed or energy loads have peaked too high for the line's capacity.

D. How are transmission service charges calculated?

Transmission service charges are based on the annual revenue requirement (ATRR) of the entity that owns the transmission infrastructure used to provide the transmission service. A transmission owner's revenue requirement is the total amount of money that FERC has authorized the transmission owner to receive in exchange for owning and maintaining the transmission lines and allowing customers to take electric transmission service over the lines (see Handbook Volume VII for more about ATRR calculations). Transmission owners recoup their revenue requirements through the monthly transmission service rates that PJM charges transmission customers. The formula used to assess these charges differs for network and point-to-point service customers.

- **Network customers** are assessed a monthly demand charge that is calculated based on their load and the applicable **Network Integration Transmission Service (NITS)** rate for a given transmission zone.[4]
- **Point-to-point service customers** are assessed service charges based on which transmission zone they are taking service to and the type of point-to-point service they have elected to receive. For more information on point-to-point accounting, refer to PJM Manual 27 Section 6.

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[2] PJM, "Manual 2: Transmission Service Request," at Section 1.1.2, 2023.

[3] PJM, "Manual 2: Transmission Service Request," at Section 1.1.1, 2023.

[4] PJM, "Manual 27: Open Access Transmission Tariff Accounting," Section 5, 2023.

E. How are the monthly demand charges for network customers calculated?

Section 34 of the PJM OATT provides the formula for calculating monthly demand charges for wholesale network service customers, and PJM Manual 27 Section 5 provides more detailed information on network service charges.

Customers' monthly demand charges include the charges for every transmission zone where they use service. In turn, the monthly demand charge for each zone equals the sum of the Daily Zonal Demand Charges for that month.

The Daily Zonal Demand Charge (also referred to as the Daily Network Service Charge) **= that customer's Daily Peak Load Contribution (PLC) *** (the NITS Rate for that Transmission Zone) **/ 365 days** (to convert the annual NITS rate into a daily rate).

1. Peak Load Contribution

According to PJM, "Peak Load Contribution (PLC) . . . parameters are calculated . . . by the electric distribution companies within PJM's territory."[5] Because PJM does not have a standard methodology for calculating these values, it offers a public database of the procedures each distribution utility uses for its respective calculations. Generally, the peak load contribution is fixed monthly, but if the network customer is taking service in a state that has a retail choice program, the peak load contribution calculations may change daily.

2. Zonal NITS Rates

Each transmission owner calculates its respective zonal NITS rate as part of its Annual Transmission Revenue Requirement. The NITS rates are expressed in dollars per megawatt year ($/MW-Year) and are posted either (a) publicly in each transmission owner's respective Attachment H to the PJM OATT, or (b) if the transmission owner operates with a formula rate, as part of their Annual Update (see Handbook Volume VII for more information on Annual Transmission Revenue Requirement calculations and formula rates).

PJM also publicly posts a quarterly list of the NITS rates by transmission zone under the Network Integration Transmission Service Revenue Requirements & Rates Section on its Billing, Settlements, & Credit webpage. The January 2024 report is provided in Figure 5.

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[5] PJM, "THEO, PLC & NSPL Methodology Inventory," last accessed December 7, 2023.

FIGURE 5. Transmission Owner ATRR and NITS Rates by Transmission Zone

Annual Transmission Revenue Requirements (ATRR) and Network Integration Transmission Service (NITS) Rates

Transmission Zone	Transmission Owner	Annual Revenue Requirement	Total Zonal Annual Revenue Requirement	Network Integration Transmission Service Rate ($/MW-Year)
AECO	Atlantic City Electric Company	$ 239,334,801.00	**$ 239,334,801.00**	**$ 91,559.00**
AEP	AEP East Operating Companies	$ 1,287,054,780.00		
	AEP East Transmission Companies	$ 1,576,044,856.00		
	AMP Transmission, LLC	$ 750,621.28		
			$ 2,863,850,257.28	**$ 125,466.60**
APS	South FirstEnergy Operating Companies	$ 159,299,229.00	**$ 159,299,229.00**	**$ 17,114.75**
ATSI	American Transmission Systems, Inc.	$ 1,031,766,861.00		
	AMP Transmission, LLC	$ 16,267,846.92		
			$ 1,048,034,707.92	**$ 87,624.38**
BGE	Baltimore Gas and Electric Company	$ 302,526,020.00	**$ 302,526,020.00**	**$ 46,400.00**
ComEd	Commonwealth Edison Company	$ 846,151,471.00	**$ 846,151,471.00**	**$ 39,796.00**
DAY	The Dayton Power and Light Company	$ 105,611,813.00		
	AMP Transmission, LLC	$ 633,168.64		
			$ 106,244,981.64	**$ 32,781.54**
DEOK	Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	$ 210,262,707.00	**$ 210,262,707.00**	**$ 40,717.00**
DOM	Virginia Electric and Power Company	$ 1,516,919,632.71	**$ 1,516,919,632.71**	**$ 68,271.28**
	Virginia Electric and Power Company (Dominion Underground)	$ 12,475,269.04	**$ 12,475,269.04**	**$ 577.80**
DPL	Delmarva Power & Light Company	$ 222,366,549.00		
	Old Dominion Electric Cooperative	$ 5,211,354.00		
			$ 227,577,903.00	**$ 55,166.00**
DUQ	Duquesne Light Company	$ 171,941,505.00	**$ 171,941,505.00**	**$ 63,330.20**
EKPC	East Kentucky Power Cooperative	$ 103,064,355.00	**$ 103,064,355.00**	**$ 34,784.00**
JCPL	Jersey Central Power and Light Company	$ 217,430,596.00	**$ 217,430,596.00**	**$ 37,937.40**
ME	Mid-Atlantic Interstate Transmission, LLC	$ 410,168,891.00	**$ 410,168,891.00**	**$ 73,260.14**
PENELEC				**$ 73,260.14**
OVEC	Ohio Valley Electric Cooperative	$ 11,256,927.00	**$ 11,256,927.00**	**$ 5,163.73**
PECO	PECO Energy Company	$ 220,129,110.00	**$ 220,129,110.00**	**$ 25,648.00**
PEPCO	Potomac Electric Power Company	$ 231,867,579.00		
	Southern Maryland Electric Cooperative	$ 17,086,212.00		
			$ 248,953,791.00	**$ 42,655.88**
PPL	PPL Electric Utilities Corporation	$ 724,534,909.00		
	Allegheny Electric Cooperative, Inc.	$ 2,584,702.00		
	UGI Utilities, Inc.	$ 11,023,445.00		
			$ 738,143,056.00	**$ 104,360.00**
PSEG	Public Service Electric & Gas Company	$ 1,729,563,805.00	**$ 1,729,563,805.00**	**$ 180,897.79**
RECO	Rockland Electric Company	$ 18,200,000.00	**$ 18,200,000.00**	**$ 46,076.00**
▨	NextEra Energy Transmission MidAtlantic Indiana	$ 1,807,858.00	▨	▨
▨	Silver Run Electric, LLC	$ 25,793,147.00	▨	▨
▨	Trans-Allegheny Insterstate Line Company	$ 278,570,075.79	▨	▨
▨	Transource West Virginia, LLC	$ 9,367,951.00	▨	▨
	TOTAL	**$ 11,717,068,047.38**	**$ 11,401,529,015.59**	

As of 1/1/2024

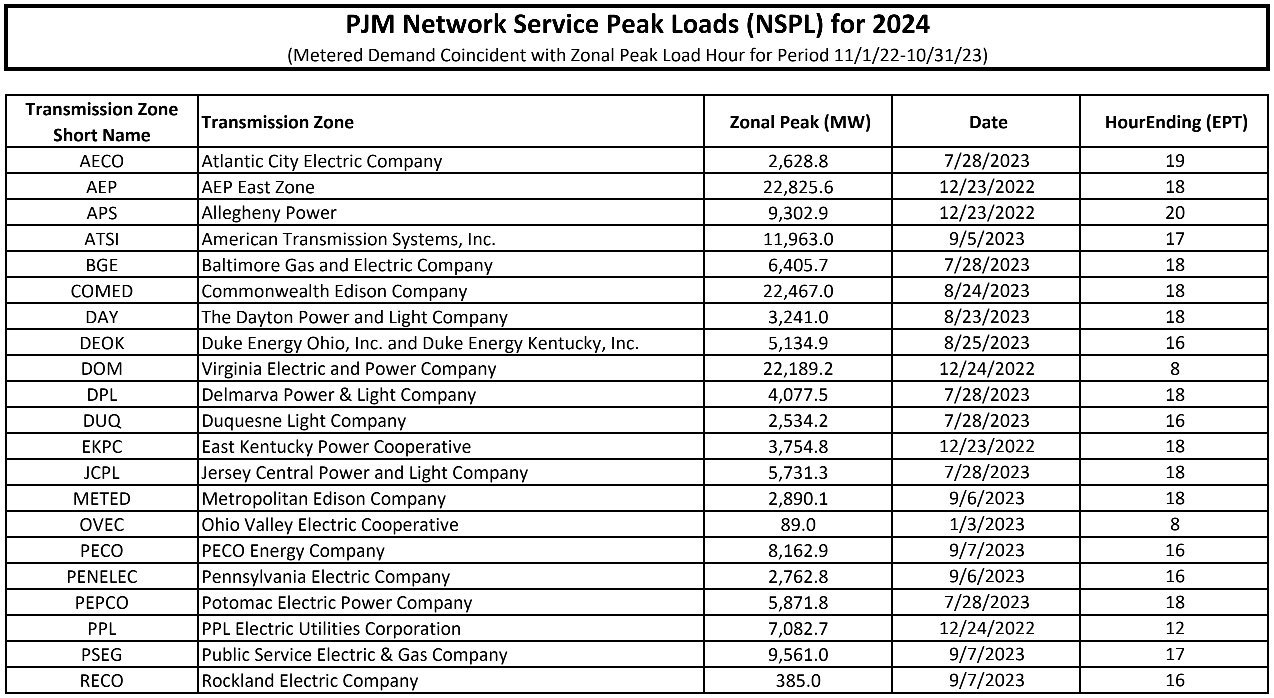
(Credit: PJM, "Annual Transmission Revenue Requirements (ATRR) and Network Integration Transmission Service (NITS) Rates," January 1, 2024).

Generally, NITS rates are calculated based on the transmission owner's total annual revenue requirement divided by the single highest peak load within that transmission zone, also referred to as the zonal Network

Peak Service Load (NPSL). In other words, the **NITS Rate = ATRR/zonal NPSL**.[6] However, some transmission owners may post a black box NITS rate, or a set value with no underlying information explaining how it derived that number. Black box rates are usually developed through litigated settlements. For the transmission owners that use the formula:

- ***Annual Transmission Revenue Requirement:*** Transmission owners' ATRRs are based on the rates that the Federal Energy Regulatory Commission (FERC) authorized the transmission owner to charge customers. To receive authorization, FERC reviews the transmission owners' rate proposal and must find that the charges are "just and reasonable." In some utility zones, this value will also include the transmission owner's transmission enhancement charges, which fund the development of new and upgraded transmission projects that have been approved for regional cost allocation. In other utility footprints, transmission enhancement charges are assessed as a standalone charge, as this Handbook Volume will discuss in more detail below.
- ***Zonal Network Peak Service Load:*** PJM determines the zonal NPSL value annually using data from November 1- October 31 of the previous year. It then publishes the values by November 15 on its Billing, Settlements, & Credits webpage under Network Service Peak Loads. The values become effective January 1 of the following year.[7] For example, PJM calculated the rates that became effective on January 1, 2024 (Figure 6) using data from November 1, 2022 - October 31, 2023.

FIGURE 6. PJM Network Transmission Service Peak Loads 2024



PJM Network Service Peak Loads (NSPL) for 2024

(Metered Demand Coincident with Zonal Peak Load Hour for Period 11/1/22-10/31/23)

Transmission Zone Short Name	Transmission Zone	Zonal Peak (MW)	Date	HourEnding (EPT)
AECO	Atlantic City Electric Company	2,628.8	7/28/2023	19
AEP	AEP East Zone	22,825.6	12/23/2022	18
APS	Allegheny Power	9,302.9	12/23/2022	20
ATSI	American Transmission Systems, Inc.	11,963.0	9/5/2023	17
BGE	Baltimore Gas and Electric Company	6,405.7	7/28/2023	18
COMED	Commonwealth Edison Company	22,467.0	8/24/2023	18
DAY	The Dayton Power and Light Company	3,241.0	8/23/2023	18
DEOK	Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	5,134.9	8/25/2023	16
DOM	Virginia Electric and Power Company	22,189.2	12/24/2022	8
DPL	Delmarva Power & Light Company	4,077.5	7/28/2023	18
DUQ	Duquesne Light Company	2,534.2	7/28/2023	16
EKPC	East Kentucky Power Cooperative	3,754.8	12/23/2022	18
JCPL	Jersey Central Power and Light Company	5,731.3	7/28/2023	18
METED	Metropolitan Edison Company	2,890.1	9/6/2023	18
OVEC	Ohio Valley Electric Cooperative	89.0	1/3/2023	8
PECO	PECO Energy Company	8,162.9	9/7/2023	16
PENELEC	Pennsylvania Electric Company	2,762.8	9/6/2023	16
PEPCO	Potomac Electric Power Company	5,871.8	7/28/2023	18
PPL	PPL Electric Utilities Corporation	7,082.7	12/24/2022	12
PSEG	Public Service Electric & Gas Company	9,561.0	9/7/2023	17
RECO	Rockland Electric Company	385.0	9/7/2023	16

(Credit: PJM, "PJM Network Service Peak Loads (NSPL) for 2024," 2023).

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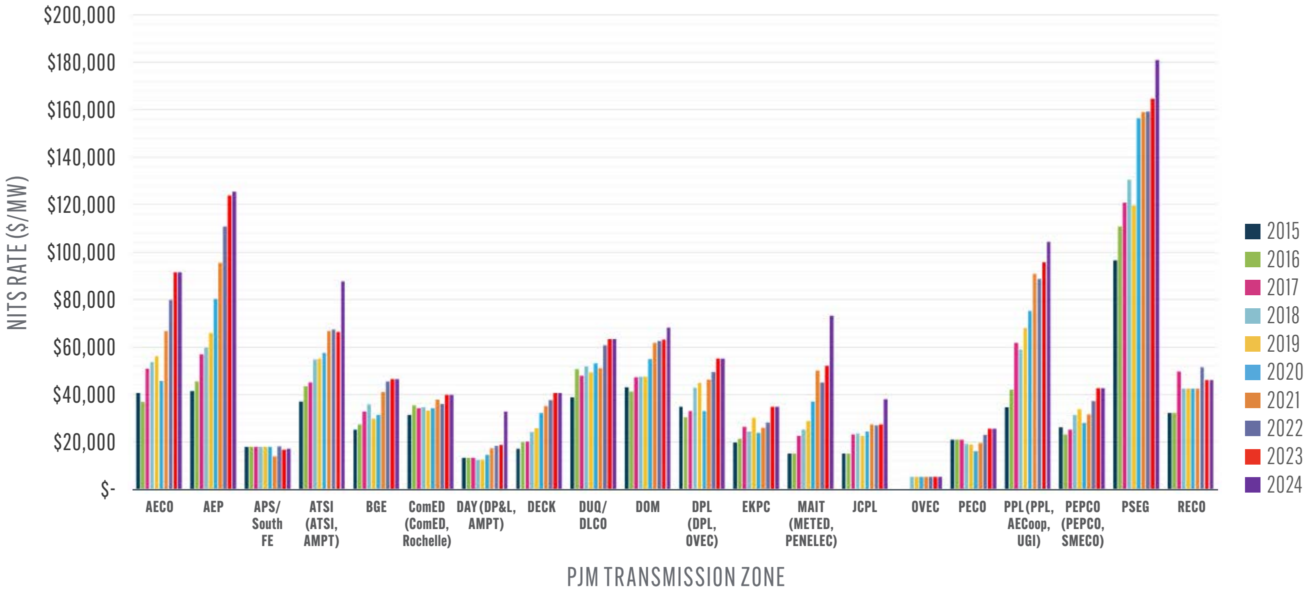
[6] Trane, "The $13 Billion A Year Mystery: An In-Depth Understanding of PJM's Demand Charges," April 3, 2018.

[7] *See*, PJM, Manual 27, Section 5.2.1.

F. Have NITS rates remained steady in PJM?

The specifics depend on the zone, but many areas within PJM have seen significant increases to their NITS rates in recent years. The past ten years of NITS rates for each transmission zone are provided in Figure 7.

FIGURE 7. NITS Rates by Transmission Zone (2015 - January 2024)



(Source Data: For years 2018-2024, PJM's Annual Transmission Revenue Requirements (ATRR) and Network Integration Transmission Service (NITS) Rates reports; For years 2015-2017, Transmission Owner rate filings which were collected for CAPS by GT Power Group).

As of January 2024, there is an exponential difference between the NITS rates in the five transmission zones with the highest rates and the five zones with the lowest rates (Figure 8).

FIGURE 8. Transmission Zones with the Highest and Lowest NITS Rates, January 2024

Transmission Zones with the Highest NITS Rates, January 2024

TO Zone	NITS Rate ($/MW-Year)
Public Service Electric and Gas Co. (PSEG)	$180,898
American Electric Power Co., Inc. (AEP)	$125,467
PPL Electric Utilities (PPL)	$104,360
Atlantic City Electric Company (ACEC or AECO)	$91,559
American Transmission Systems, Inc. (ATSI)	$87,624

Transmission Zones with the Lowest NITS Rates, January 2024

TO Zone	NITS Rate ($/MW-Year)
Ohio Valley Electric Corporation (OVEC)	$5,164
Allegheny Power Systems (APS/South FirstEnergy Operating Companies)	$17,115
PECO Energy (PECO)	$25,648
Dayton Power and Light Company (DAY)	$32,782
East Kentucky Power Cooperative (EKPC)	$34,784

(Source Data: PJM, "Annual Transmission Revenue Requirements (ATRR) and Network Integration Transmission Service (NITS) Rates," Jan. 1, 2024).

Between 2015 and January 2022, NITS rates in ten transmission zones have increased more than 80%, with eight zones facing rates that have more than doubled and one zone having a close to 400% rate increase.

FIGURE 9. NITS Rate Increases from 2015 – January 2024

Increase in NITS Rates from 2015 to January 2024

TO Zone	Cumulative Increase
Mid-Atlantic Interstate Transmission LLC (MAIT) (includes Metropolitan Edison Company (MEC) and Pennsylvania Electric Company (PE or PENELEC))	385%
American Electric Power Co., Inc. (AEP)	203%
PPL Electric Utilities (PPL)	202%
Jersey Central Power and Light Co. (JCPL)	151%
Dayton Power and Light Company (DAY)	147%
Duke Energy Ohio and Kentucky (DEOK or DUKE)	139%
American Transmission Systems, Inc. (ATSI)	137%
Atlantic City Electric Company (AECO/ACEC)	125%
Public Service Electric and Gas Co. (PSEG)	87%
Baltimore Gas and Electric Company (BGE)	84%

(Source Data: For years 2018-2024, PJM's Annual Transmission Revenue Requirements (ATRR) and Network Integration Transmission Service (NITS) Rates reports; For years 2015-2017, Transmission Owner rate filings which were collected for CAPS by GT Power Group).

G. Why would NITS rates increase?

NITS rates might increase due to new infrastructure build-out. Some transmission owners have needed to make significant system enhancements to replace aging infrastructure, incorporate distributed resources, account for increasing electricity demand, and ensure that transmission lines are reliable in the face of frequent extreme weather events. As PJM explained in 2019:

> **Two-thirds of all system assets in PJM are more than 40 years old; over one-third are more than 50 years old. Some local, lower-voltage transmission facilities, especially below 230 kV, are approaching 90 years old.**[8]

NITS rates can also rise if the capital costs of those projects are incorporated into the transmission owner's annual transmission revenue requirement. And as newer transmission lines go into service, the costs to operate and maintain those lines go into transmission owner's annual transmission revenue requirement.

Transmission owners operating on formula rates integrate their true-up adjustments into the next rate year. Large true-up adjustments can also impact the NITS rates.

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[8] PJM Interconnection, "The Benefits of the PJM Transmission System," at 5, 2019.

03

Transmission Enhancement Charges

A. How are regional transmission project development costs divided up between wholesale customers in PJM?

When transmission owners in PJM build or upgrade transmission lines, they will pass those costs on to transmission customers receiving electric service over that line. The first step in passing on the costs of regional projects is deciding which customers should be responsible for paying for the costs of the projects, or **cost allocation**. Federal law requires those costs be allocated to customers in a manner that is "roughly commensurate" with the benefits they currently receive or will receive from the service in the future.[9] The law also requires such costs be "just and reasonable."[10]

Think of **cost allocation** like cutting slices of a pie, where the pie represents the total cost of developing a transmission project and the cost allocation methodologies are the tool used to decide what percentage of the pie should be allocated to each utility footprint, or transmission zone, whose customers will benefit from the project. In a very simplified example, if the wholesale customers in Transmission Zone A and Transmission Zone B will benefit equally from a transmission project, then the costs are allocated 50% to Transmission Zone A and 50% to Transmission Zone B. As discussed more in the next section, however, cost allocation in PJM is not that simple.

Under PJM's governing documents, the PJM *transmission owners are responsible for proposing cost allocation methodologies* to FERC to review and approve (see Handbook Volume II to learn more about PJM's governing documents, including the Transmission Owner's Agreement). PJM's job is to administer the FERC-approved cost allocation methodologies and allocate the appropriate ratio of costs to the customers in the responsible transmission zones.

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[9] *Preventing Undue Discrimination & Preference in Transmission Serv.,* Order No. 890, 118 FERC ¶ 61,119, PP 622, 637, 72 Fed. Reg. 12,226, *order on reh'g,* Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g,* Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890-D, 129 FERC ¶ 61,126 (2009); *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.,* Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000-A, 77 Fed. Reg. 32184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh'g and clarification,* Order No. 1000 -B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d 41 (D.C. Cir. 2014); *see also Illinois Commerce Commission v. FERC,* 576 F.3d 470, 476 (7th Cir., 2009).

[10] 16 U.S.C. § 824d.

The second step in passing on the costs of building regional projects is referred to as **cost recovery**. In this step, the transmission owner must first obtain an order from FERC stating that the project costs the transmission owner is seeking to recover are "just and reasonable." PJM again administers the calculations and integrates the authorized costs into the transmission enhancement charges for each zone.

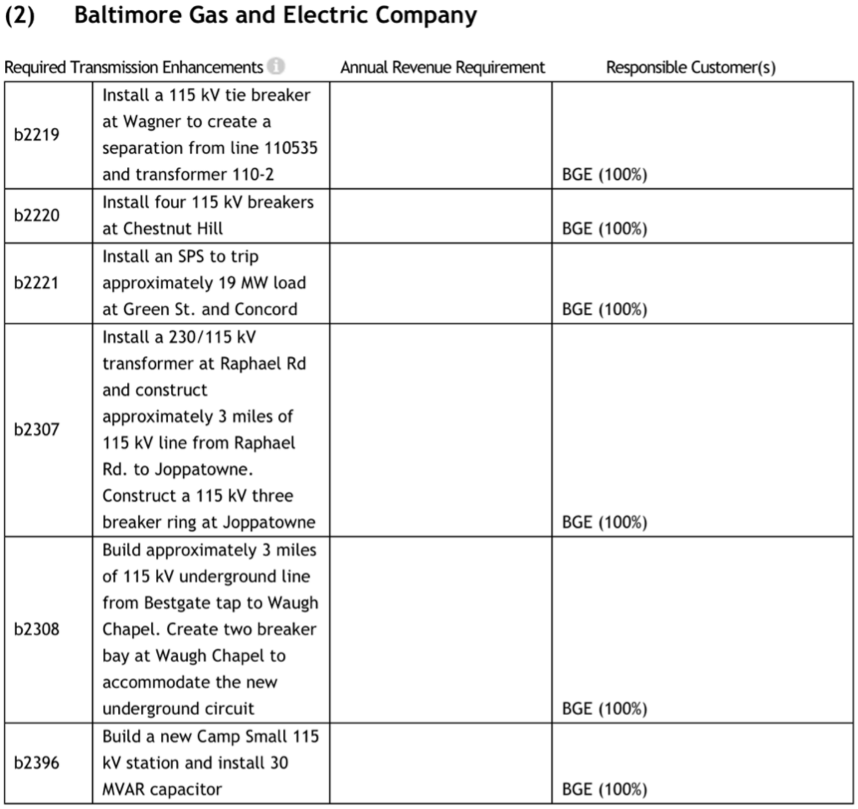
B. Cost Allocation

1. How do the transmission owners determine who benefits from, and therefore who should pay for a transmission line?

The cost allocation methods used in PJM are described in Schedule 12 of PJM's Open Access Transmission Tariff and depend on project's location, voltage, and other factors.

Projects located all in one transmission zone. Most projects located fully within one transmission zone (e.g. one utility footprint) are assumed to solely benefit the customers in that zone. As such, 100% of the project costs are assigned to the wholesale customers that take service in that transmission zone. This method is referred to as a **direct allocation** and usually applies to lower voltage facilities (below 345 kV). An example of direct allocation is provided below in Figure 10. The projects listed in Figure 10 are located exclusively within Baltimore Gas and Electric Company (BGE) territory, so the costs are solely allocated to the wholesale customers who take service in the BGE transmission zone. These wholesale customers include the distribution utility (also named BGE) who, as discussed in Handbook Volume III, passes the transmission costs to its end-use customers through its electric utility bills.

FIGURE 10. Example of Direct Cost Allocation



(2) Baltimore Gas and Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2219	Install a 115 kV tie breaker at Wagner to create a separation from line 110535 and transformer 110-2		BGE (100%)
b2220	Install four 115 kV breakers at Chestnut Hill		BGE (100%)
b2221	Install an SPS to trip approximately 19 MW load at Green St. and Concord		BGE (100%)
b2307	Install a 230/115 kV transformer at Raphael Rd and construct approximately 3 miles of 115 kV line from Raphael Rd. to Joppatowne. Construct a 115 kV three breaker ring at Joppatowne		BGE (100%)
b2308	Build approximately 3 miles of 115 kV underground line from Bestgate tap to Waugh Chapel. Create two breaker bay at Waugh Chapel to accommodate the new underground circuit		BGE (100%)
b2396	Build a new Camp Small 115 kV station and install 30 MVAR capacitor		BGE (100%)

(Credit: PJM, "OATT," Schedule 12: Transmission Enhancement Charges, Appendix A-2, Baltimore Gas & Electric Company, last accessed December 15, 2023).

Projects that cross wholesale customer footprints. Projects in PJM that cross multiple transmission zones, or that benefit customers across multiple transmission zones, are allocated in one of three ways:

> ***Methodology 1:*** *Load ratio share.* In very simple terms, this method divides costs between the zones that benefit from the transmission line based on each zone's respective peak load, or the maximum amount of power delivered to that zone or customer on a given day. PJM calculates load ratio shares based on the non-coincident peak load for each responsible zone.
>
> ***Methodology 2:*** *Solution-Based DFAX, or Distribution Factor Analysis.* This method approximates the contribution a customer zone will make to the power flows over the new line. As described in PJM's OATT Schedule 12, the calculation for the DFAX Analysis for reliability projects is as follows:

Distribution Factor = (After-shift power flow - pre-shift power flow) / Total amount of power shifted

Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility

Pre-shift power flow = Megawatt flow over the Required Transmission Enhancement before the incremental megawatt transfer

After-shift power flow = Megawatt flow over the Required Transmission Enhancement after the incremental megawatt transfer

Typically, the DFAX method is applied when the transmission project is:

- an alternating current (AC) facility with a budget of at least $5 million with a lower voltage, usually below 500 kV;
- a lower voltage facility that is a reliability project;[11] or
- a regional facility approved through PJM's Regional Transmission Expansion Plan (RTEP) with a budget of at least $5 million that has a voltage of at least 500 kV, or 345kV for double circuit lines (in this instance, the cost allocation process may involve a hybrid of two allocation methodologies, with 50% of costs allocated through DFAX and 50% allocated using the load ratio share method described above).[12] Figure 11 provides examples of a hybrid cost allocation (Project b2633.7) and a Load Ratio share allocation (Project b2633.10). Though these projects are owned by Delmarva Power & Light Company, the costs are allocated across multiple transmission zones because transmission customers in other zones will also benefit from the project.

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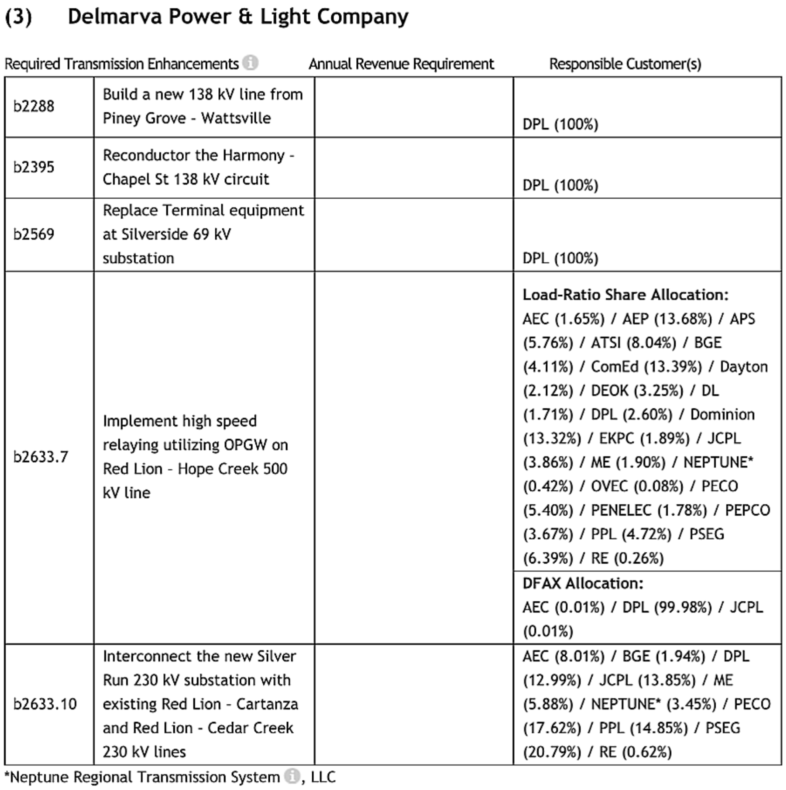
[11] PJM, "OATT," Schedule 12.

[12] PJM, "Cost Allocation Education," Slides 3-4, 2020.

FIGURE 11. Example of Hybrid DFAX and Load-Ration Share Allocations



(3) Delmarva Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2288	Build a new 138 kV line from Piney Grove - Wattsville		DPL (100%)
b2395	Reconductor the Harmony - Chapel St 138 kV circuit		DPL (100%)
b2569	Replace Terminal equipment at Silverside 69 kV substation		DPL (100%)
b2633.7	Implement high speed relaying utilizing OPGW on Red Lion - Hope Creek 500 kV line		**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.10	Interconnect the new Silver Run 230 kV substation with existing Red Lion - Cartanza and Red Lion - Cedar Creek 230 kV lines		AEC (8.01%) / BGE (1.94%) / DPL (12.99%) / JCPL (13.85%) / ME (5.88%) / NEPTUNE* (3.45%) / PECO (17.62%) / PPL (14.85%) / PSEG (20.79%) / RE (0.62%)

*Neptune Regional Transmission System, LLC

(Credit: PJM, "OATT," Schedule 12: Transmission Enhancement Charges, Appendix A-3, Delmarva Power & Light Company, last accessed December 15, 2023).

Methodology 3: *State agreement approach.* Under this approach, one or more states can voluntarily agree to pay for all or a portion of the transmission project because they want to address their state's public policy objectives (such as a clean energy target)[13] and the RTEP process has not produced a project that would address those concerns. New Jersey became the first to execute a cost allocation agreement under the state agreement approach in 2021; it did so to develop a transmission line to transport power from offshore wind facilities.[14]

2. Where can customers find information about project costs and the cost allocation methods used for a project?

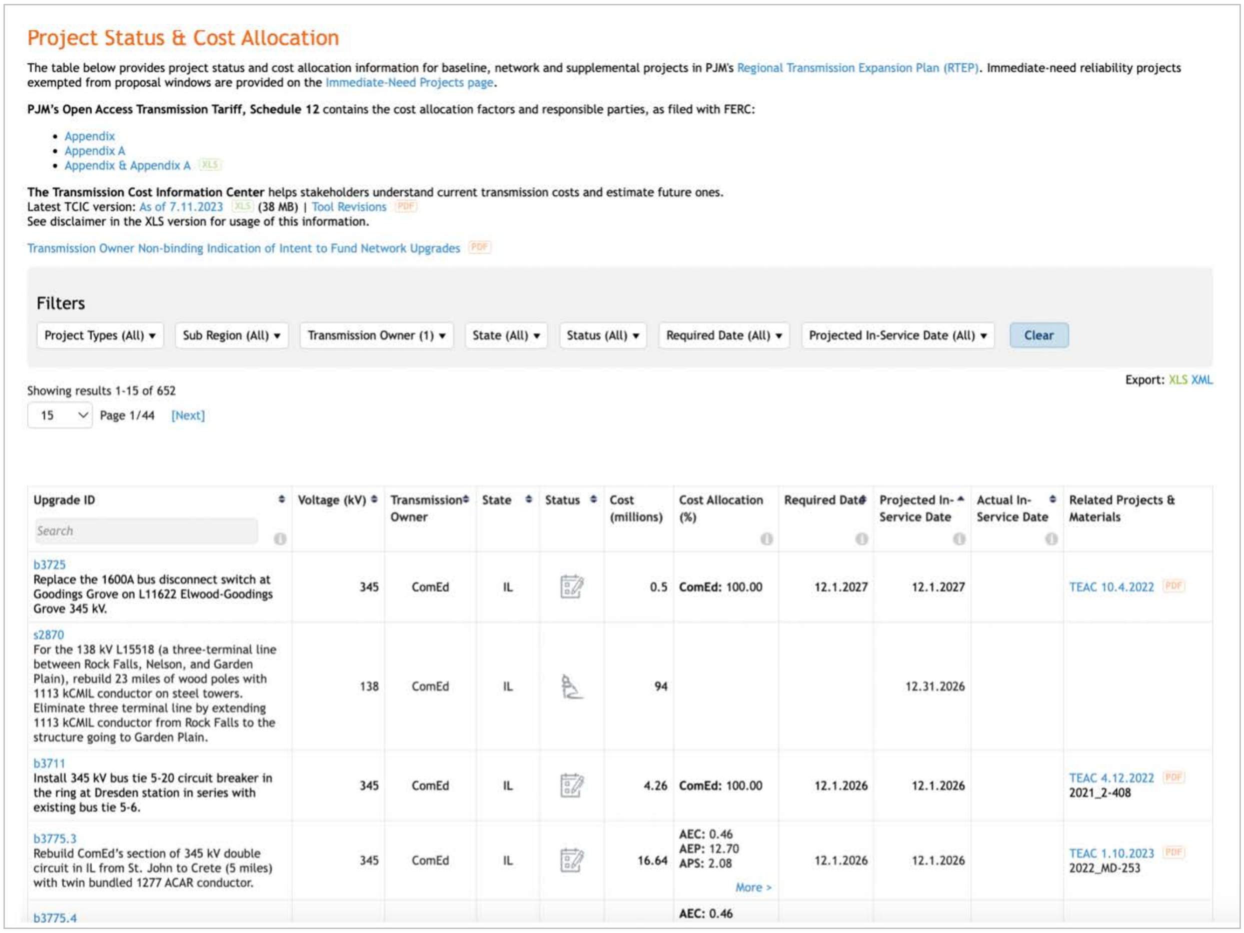
PJM provides comprehensive information on its Project Status & Cost Allocation webpage, including details on project names, status, cost allocation, and driver for all completed and pending projects.

---

[13] See Handbook Volume IV for more information on public policy drivers of transmission development in PJM.

[14] See, e.g. NJ BPU., "New Jersey's 2021 Offshore Wind Transmission Competitive Solicitation under PJM State Agreement Approach," December 28, 2021; see also Organization of PJM States, Inc., "Memo: State Agreement Approach," June 12, 2012.

FIGURE 12. Screenshot of PJM's Project Status & Cost Allocation Database



Project Status & Cost Allocation

The table below provides project status and cost allocation information for baseline, network and supplemental projects in PJM's Regional Transmission Expansion Plan (RTEP). Immediate-need reliability projects exempted from proposal windows are provided on the Immediate-Need Projects page.

PJM's Open Access Transmission Tariff, Schedule 12 contains the cost allocation factors and responsible parties, as filed with FERC:

- Appendix
- Appendix A
- Appendix & Appendix A XLS

The Transmission Cost Information Center helps stakeholders understand current transmission costs and estimate future ones.
Latest TCIC version: As of 7.11.2023 XLS (38 MB) | Tool Revisions PDF
See disclaimer in the XLS version for usage of this information.

Transmission Owner Non-binding Indication of Intent to Fund Network Upgrades PDF

Filters

Project Types (All) ▾ | Sub Region (All) ▾ | Transmission Owner (1) ▾ | State (All) ▾ | Status (All) ▾ | Required Date (All) ▾ | Projected In-Service Date (All) ▾ | Clear

Export: XLS XML

Showing results 1-15 of 652

15 Page 1/44 [Next]

Upgrade ID	Voltage (kV)	Transmission Owner	State	Status	Cost (millions)	Cost Allocation (%)	Required Date	Projected In-Service Date	Actual In-Service Date	Related Projects & Materials
b3725 Replace the 1600A bus disconnect switch at Goodings Grove on L11622 Elwood-Goodings Grove 345 kV.	345	ComEd	IL		0.5	ComEd: 100.00	12.1.2027	12.1.2027		TEAC 10.4.2022 PDF
s2870 For the 138 kV L15518 (a three-terminal line between Rock Falls, Nelson, and Garden Plain), rebuild 23 miles of wood poles with 1113 kCMIL conductor on steel towers. Eliminate three terminal line by extending 1113 kCMIL conductor from Rock Falls to the structure going to Garden Plain.	138	ComEd	IL		94			12.31.2026		
b3711 Install 345 kV bus tie 5-20 circuit breaker in the ring at Dresden station in series with existing bus tie 5-6.	345	ComEd	IL		4.26	ComEd: 100.00	12.1.2026	12.1.2026		TEAC 4.12.2022 PDF 2021_2-408
b3775.3 Rebuild ComEd's section of 345 kV double circuit in IL from St. John to Crete (5 miles) with twin bundled 1277 ACAR conductor.	345	ComEd	IL		16.64	AEC: 0.46 AEP: 12.70 APS: 2.08 More >	12.1.2026	12.1.2026		TEAC 1.10.2023 PDF 2022_MD-253
b3775.4						AEC: 0.46				

(Credit: PJM, "Project Status & Cost Allocation," last accessed Dec. 22, 2023).

Schedule 12 of PJM's Tariff is the other main source for information on cost allocation. Schedule 12 includes several appendices that collectively identify the transmission owner or entity responsible for constructing the project, the customer(s) responsible for the costs, and applicable cost allocation percentages. The specific topics covered by each Appendix include:

- ***Schedule 12.Appendix:*** Required Transmission Enhancements that have been placed in service in PJM before the effective tariff filing date;
- ***Schedule 12.Appendix A:*** Required Transmission Enhancements approved in the RTEP process or made by the Transmission Owner after February 1, 2013:
- ***Schedule 12-C.Appendix-A:*** Covered Transmission Enhancements post January 1, 2016;
- ***Schedule 12-C.Appendix B and Schedule 12-C.Appendix C:*** Cancelled Projects;
- ***Schedule 12.Appendix B:*** Interregional Projects; and
- ***Schedule 12.Appendix C:*** State Agreement Public Policy Projects.

Although the Section 12 appendices generally present information by transmission owner, the FERC-accepted version of the Tariff (a PDF) is dense and may be difficult to navigate. The online version of the Tariff is more user friendly and presents the projects in a table format (although not as a sortable database). While the online Tariff might be easier to navigate, it is an unofficial version and not legally binding.

C. Cost Recovery

1. How does a transmission owner recover costs associated with building regional transmission projects?

To re-coup regional transmission project costs, the transmission owner must obtain FERC authority to charge customers. A transmission owner may only recover costs associated with the project—including construction, a return on the capital investment, and maintenance and operation of the line—if FERC determines that such costs were prudently incurred and are just and reasonable (the process transmission owners use to seek FERC authority is explored in Handbook Volume VII). Continuing the earlier pie analogy, FERC's decision on project cost recovery impacts the size of the overall pie, and therefore, the numerical cost responsibilities for each transmission zone.

2. What are transmission enhancement charges?

As discussed earlier, PJM transmission enhancement charges reflect the costs that FERC has approved a transmission owner may recover for building and upgrading transmission infrastructure approved through PJM's Regional Transmission Expansion Plan. Transmission enhancement charges do not reflect "supplemental" transmission projects that are developed outside the RTEP process (see Handbook Volume IV for more information on how PJM plans transmission).

To recover project costs, transmission owners must:[15]

(1) Post the required transmission enhancements to which each transmission enhancement charge corresponds on the PJM website; and

(2) Determine the annual revenue requirement associated with a required transmission enhancement either by: (1) submitting a unilateral filing under Section 205 of the Federal Power Act and FERC regulations; or (2) including the costs associated with the enhancement in a formula rate that is in effect and applicable to the transmission owner's NITS rates. Transmission enhancement charges are expressed as monthly charges based on all the costs and applicable incentives associated with a particular required transmission enhancement.

Once the transmission owner receives FERC approval to recover its costs, PJM administers the calculations for the transmission enhancement charges based on Schedule 12 of its Open Access Transmission Tariff and Manual 27. Under Schedule 12, PJM calculates the transmission enhancement charges differently based on the type of customer:

- For network customers, each charge is recalculated annually and posted on the PJM website by October 31 of each calendar year.
- For customers using point-to-point service, each charge is calculated monthly.
- For merchant transmission facility owners, each charge is calculated as a fixed monthly charge.

PJM Manual 27, Section 10.3 further explains that:

> All network customers serving load in a responsible zone pay for that zone's applicable share of all required transmission enhancement projects' revenue requirements in proportion to their network service peak load share in that zone. Merchant transmission owners also pay their share of the applicable required transmission enhancement projects' revenue requirements.[16]

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[15] PJM, "OATT," at Schedule 12, Section A: Establishment of Enhancement Charges."

[16] PJM, "Manual 27: Open Access Transmission Tariff Accounting," Section 10: Transmission Enhancement Accounting, Revision 101, 2023.

3. How are transmission enhancement charges billed?

Transmission enhancement charges are sometimes assessed as a standalone charge to wholesale customers. Other times, they are incorporated into the NITS rate—the PJM tariff allows transmission owners to choose which method they prefer.

To determine whether a transmission owner's NITS rate includes its transmission enhancement charges, advocates should either look to the respective transmission owner's filed rate (in PJM OATT Attachment H) or to PJM's posted transmission enhancement charges settlement worksheets. As PJM Manual 27, Section 10.2.1 explains:[17]

> If the Transmission Owner recovers their costs through its Network Integration Transmission Service (NITS) rate, then the Transmission Owner will not receive a Transmission Enhancement Credit on its monthly billing statement. Rather, these costs will be included in the Transmission Owner's Network Integration Transmission Service credit billing line item. In addition, **Network Customers in the Transmission Owner's Zone will receive a Transmission Enhancement Credit on their monthly billing statement for the total costs allocated for the Required Transmission Enhancement projects**. This Transmission Enhancement credit is allocated to the Network Customers in the applicable zone based on each customer's respective Network Service Peak Load ratio share.

If a transmission owner incorporates their transmission enhancement charges into their NITS rates, then the transmission enhancement charges settlement worksheets will indicate in the (blue) label above each set of the transmission owner's projects that the "Required Transmission Enhancement" is "owned by" that transmission owner's "Network Customers." Additionally, in the table of "TEC Rates," the row indicating the Total Monthly Network Customer Credits will not be blank for that transmission owner. Just because a transmission owner includes its own transmission charges in its NITS rates, that does not mean customers in its transmission zone will be shielded from separate transmission enhancement charges. If that transmission zone is allocated costs from projects owned by other transmission owners, then the costs for those projects will flow through separate transmission enhancement charges and not the zonal NITS rate.

4. Where can customers find information about their transmission enhancement charges?

PJM publishes a transmission enhancement charges settlement worksheet that lists every PJM-required transmission enhancement by transmission owner and zone on its Billing Settlements, and Credits webpage located under the heading "Transmission Enhancement Worksheets." PJM generally posts worksheets at least twice a year (January and June) to correspond with annual formula rate update periods but will also post new interim worksheets when the charges are adjusted for other reasons such as for cost allocation updates or FERC orders. For example, on December 29, 2023, PJM posted a worksheet to account for FERC's order accepting the Potomac-Appalachian Transmission Highline (PATH) settlement.[18]

5. Have transmission enhancement charges remained steady in PJM?

It depends on the zone. Figure 13 provides the 2019 - January 2024 monthly transmission enhancement charge rates ($/MW per month) by transmission zone. The data for this chart is based on data on the "TEC_Rates" tab in PJM's posted worksheets from June of each relevant year plus the January 2024 worksheet. While PJM's website provides worksheets from years prior to 2019, the earlier reports do not provide a summary of charges by transmission zone.

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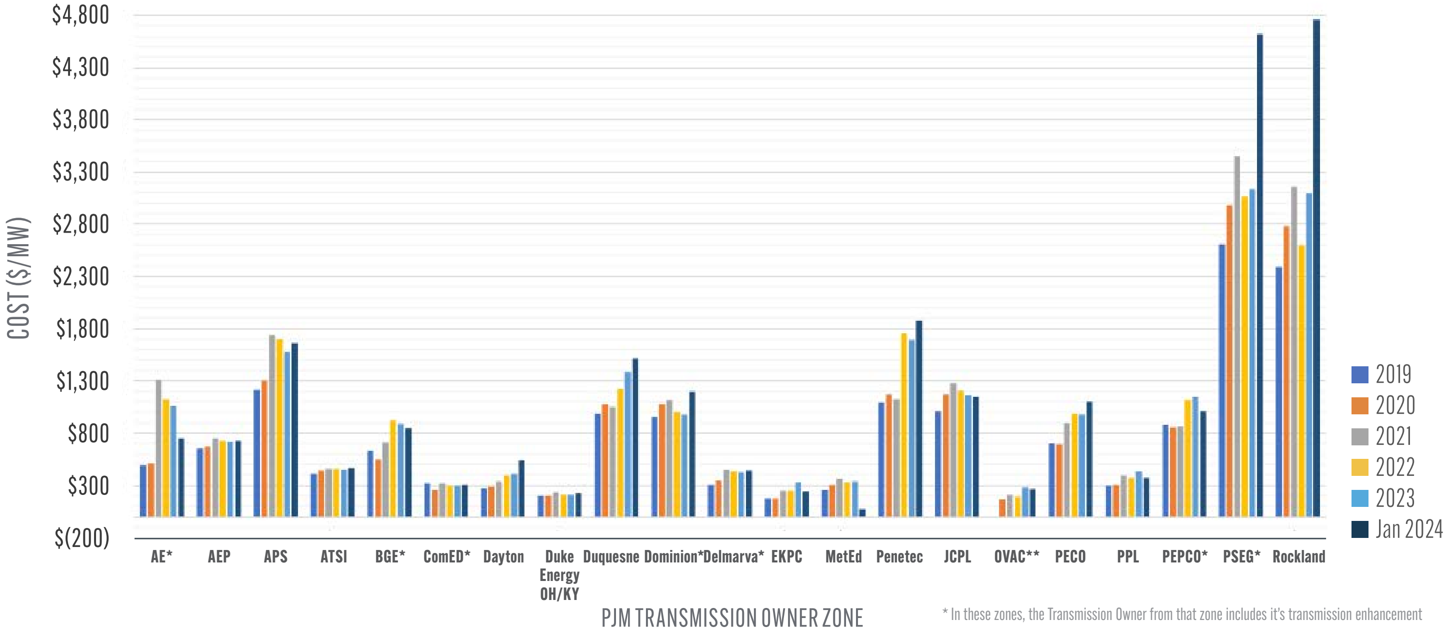
[17] PJM, "Manual 27," Section 10.2.1, at 53, 2023 (emphasis added).

[18] Potomac-Appalachian Transmission Highline, LLC and PJM Interconnection, L.L.C., 185 FERC ¶ 61,198, 2023.

FIGURE 13. Monthly PJM Transmission Enhancement Charge Rates ($/MW) by Transmission Zone Based on Annual June Settlement Worksheets 2019 - 2023 and January 2024 Settlement Worksheet



* In these zones, the Transmission Owner from that zone includes it's transmission enhancement charges in its NITS rate.

** OVAC is not included as a PJM to zone for transmission enhancement charges in 2019

(Source Data: PJM, "Billing, Settlements & Credit," Transmission Enhancement Worksheets, 2019-2024).

Like the current NITS rates, there is a significant difference in the transmission enhancement charges for the five transmission zones with the highest charges and the five with the lowest charges (see Figure 14).

FIGURE 14. Transmission Zones with the Highest and Lowest TEC Charges, January 2024

Transmission Zones with the Highest TEC Rates, January 2024

TO Zone	TEC Charges ($/MW (per month))
Rockland Electric Company (REC)	$4,761
Public Service Electric and Gas Co. (PSEG)*	$4,621
Pennsylvania Electric Company (PE or Penelec)	$1,878
Allegheny Power Systems (APS)	$1,660
Duquesne Light (DUQ)*	$1,515

Transmission Zones with the Lowest TEC Rates, January 2024

TO Zone	TEC Charges ($/MW (per month))
Metropolitan Edison Company (MetEd)	$71
Duke Energy Ohio and Kentucky (Duke Energy)	$221
East Kentucky Power Cooperative (EKPC)	$242
Ohio Valley Electric Corporation (OVEC)	$261
ComEd*	$308

(Source Data: PJM, "Billing, Settlements & Credit," Transmission Enhancement Worksheets, January 2024).

The five zones with the highest transmission enhancement charges cumulatively account for more than 50% of the total transmission enhancement charges across all the PJM zones.

The following four zones have Transmission Enhancement Charges increases of more than 50% (between 2019 and January 2024).

FIGURE 15. NITS Rate Increases

Increase in NITS Rates from 2019 to January 2024

TO Zone	Cumulative Increase
Rockland Electric Company (REC)	99.3%
Dayton Power & Light (DAY)	96.5%
Public Service Electric and Gas Co. (PSEG)*	77.1%
Pennsylvania Electric Company (Penelec or PE)	72.4%

(Source Data: PJM, "Billing, Settlements & Credit," Transmission Enhancement Worksheets, 2019-2024).

04

Other Transmission-Related Charges

In addition to transmission service and transmission enhancement charges, the PJM Tariff and Operating Agreement outline a few other transmission-related charges that may be assessed on wholesale customers' bills, including:

- **Transmission Congestion**—charges that are incurred when PJM's transmission system is constrained and energy must be re-dispatched,
- **Transmission Losses**—charges assessed to market participants that reflect the increased costs of energy due to transmission losses,
- **Ancillary Services,** such as *Transmission Owner Scheduling, System Control and Dispatch Service*—charges for operation of PJM transmission owners' control centers— and *Reactive Supply and Voltage Control from Generation Sources*—charges for operating generating facilities to produce reactive power to maintain transmission voltages within acceptable limits, and
- **Additional Fees**—charges to provide funding for the Organization of PJM States (OPSI), CAPS, North American Electric Reliability Corporation (NERC), and the Reliability First Corporation (RFC).

05

How Does PJM Collect Payments for Transmission Service?

PJM tracks transmission service charges and issues a monthly settlement bill to the wholesale customer. If the customer is entitled to any revenue—for example, the transmission customer is also a transmission owner entitled to receive revenue for the use of their lines—then PJM will also credit such revenues on the bill, as shown in Figure 16.

Figure 16. PJM Billing Statement Example

pjm | Settlement

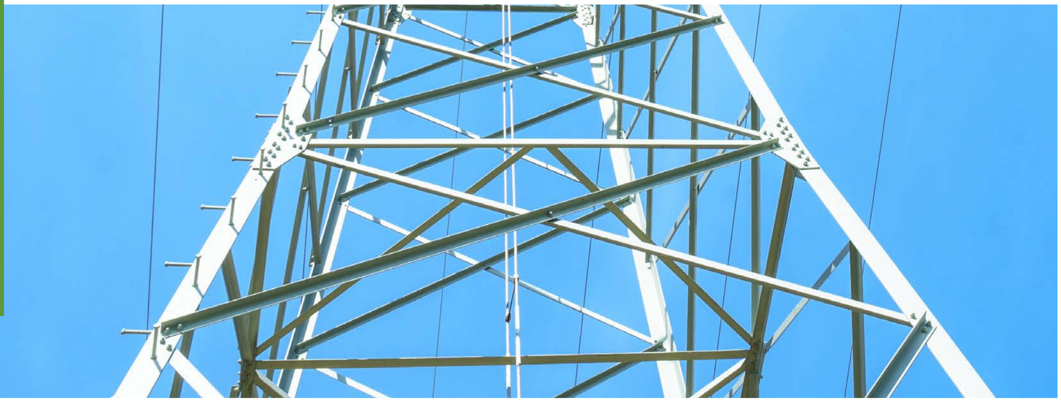
PJM Settlement, Inc.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER: 2010073198765
CUSTOMER ACCOUNT: John Doe Energy
CUSTOMER IDENTIFIERS: JDE (98765)
FINAL BILLING STATEMENT ISSUED: 08/06/2010 10:26:21
BILLING PERIOD: 07/01/2010 to 07/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		15,016,644.01
1108		Transmission Enhancement		43,314.35
1120		Other Supporting Facilities		10,434
1130		Firm Point-to-Point Transmission Service		11.45
1140		Non-Firm Point-to-Point Transmission Service		914,444.13
1200		Day-Ahead Spot Market Energy		(478,064.75)
1205		Balancing Spot Market Energy		(734,735.44)
1210		Day-Ahead Transmission Congestion		35,094.43
1215		Balancing Transmission Congestion		(838,404.58)
1218		Planning Period Congestion Uplift		16,101,200.01
1220		Day-Ahead Transmission Losses		44,946.65
1225		Balancing Transmission Losses		(3,847.17)
1230		Inadvertent Interchange		(47.34)
1250		Meter Error Correction		48,711.91
1260		Emergency Energy		(38,890.94)
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		391.63
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		10,786.81
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		704.44
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		4,444.47
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		4,543.74
1306		PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		(7,135.79)
1307		PJM Scheduling, System Control and Dispatch Service - Market Support Offset		(8,243.82)
1308		PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		(46.75)
1309		PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		(1,700.49)
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		(145.19)
1311		PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		(301.50)
1312		PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.		1,349.35
1313		PJM Settlement, Inc.		3,143.74
1314		Market Monitoring Unit (MMU) Funding		16,804.78
1315		FERC Annual Recovery		148.11
1316		Organization of PJM States, Inc. (OPSI) Funding		4,181.13
1317		North American Electric Reliability Corporation(NERC)		3,985.46
1318		Reliability First Corporation (RFC)		59,859.94
1320		Transmission Owner Scheduling, System Control and Dispatch Service		46,888.44

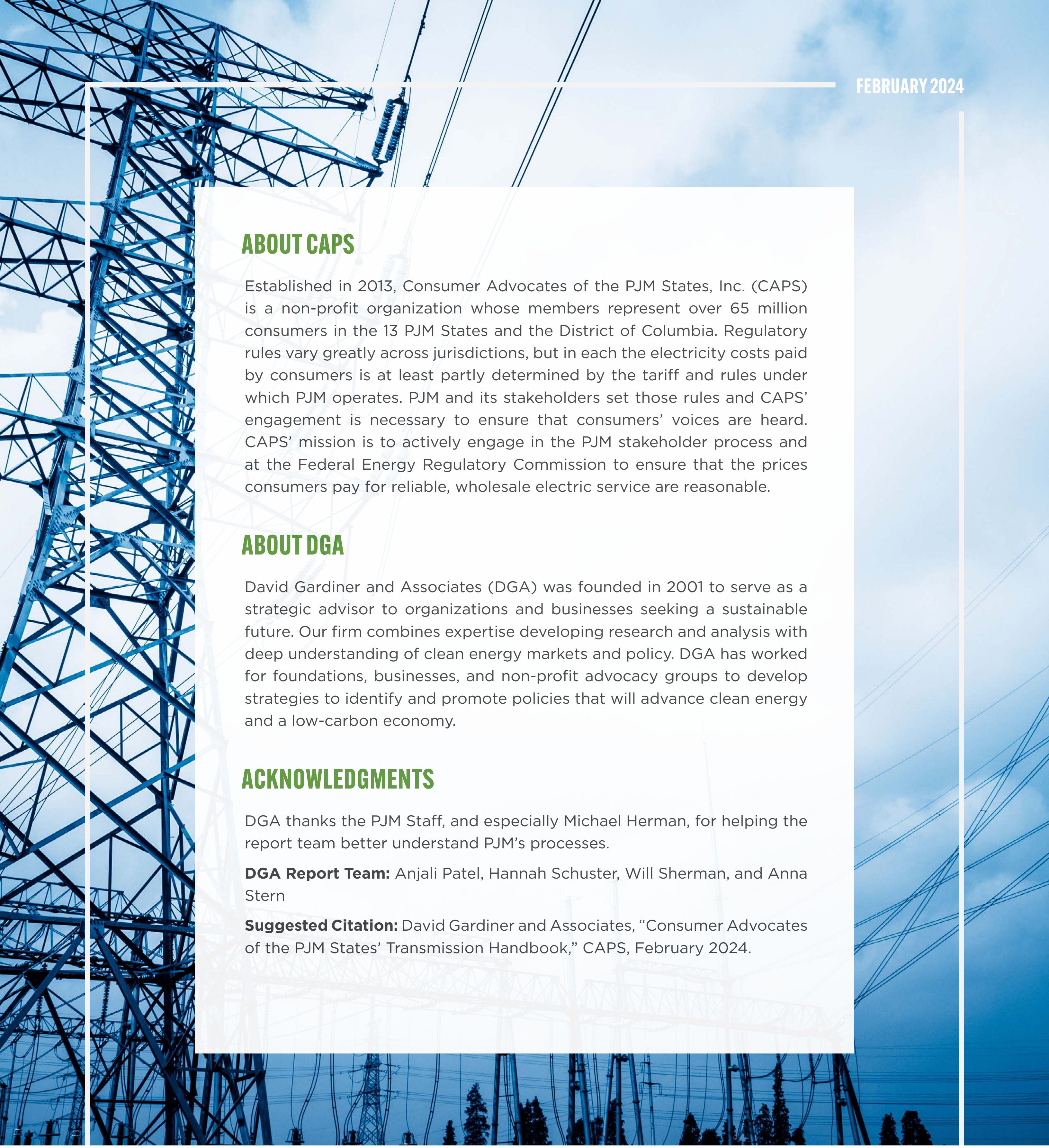
(Credit: PJM, "Monthly Billing Statement Example," last accessed December 7, 2023).

06



Advocacy Opportunities Related to Transmission Charges

PJM Planning Processes and Transmission Rate Cases: The best advocacy avenues to promote cost-effective and equitable transmission charges are PJM's planning processes and the transmission owners' rate cases. More information about these advocacy opportunities can be found in Handbook Volumes IV and VII, respectively.



FEBRUARY 2024

ABOUT CAPS

Established in 2013, Consumer Advocates of the PJM States, Inc. (CAPS) is a non-profit organization whose members represent over 65 million consumers in the 13 PJM States and the District of Columbia. Regulatory rules vary greatly across jurisdictions, but in each the electricity costs paid by consumers is at least partly determined by the tariff and rules under which PJM operates. PJM and its stakeholders set those rules and CAPS' engagement is necessary to ensure that consumers' voices are heard. CAPS' mission is to actively engage in the PJM stakeholder process and at the Federal Energy Regulatory Commission to ensure that the prices consumers pay for reliable, wholesale electric service are reasonable.

ABOUT DGA

David Gardiner and Associates (DGA) was founded in 2001 to serve as a strategic advisor to organizations and businesses seeking a sustainable future. Our firm combines expertise developing research and analysis with deep understanding of clean energy markets and policy. DGA has worked for foundations, businesses, and non-profit advocacy groups to develop strategies to identify and promote policies that will advance clean energy and a low-carbon economy.

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DGA Report Team: Anjali Patel, Hannah Schuster, Will Sherman, and Anna Stern

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