COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY POWER COMPANY FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022	)))))	Case No. 2023-00008

DIRECT TESTIMONY OF

JOSHUA D. BURKHOLDER

ON BEHALF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joshua D. Burkholder, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by American Electric Power Service Corporation ("AEPSC") as Managing Director – Transmission RTO Policy. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power ("AEP") system, one of which is Kentucky Power Company ("Kentucky Power" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a bachelor's degree with honors in economics in 1997 from the University of Maryland in College Park, MD. I graduated from The Ohio State University, Fisher College of Business with a Masters of Business Administration in 2002.

From 1997 to 2000, I held the position of Economist at the U.S Department of Commerce, Bureau of Economic Analysis, where I participated in analysis of international financial data.

I joined AEPSC in 2002 as an associate in commercial operations and worked on various business development projects and AEP's integration into PJM Interconnection, LLC ("PJM"). In 2004, I joined AEPSC's Corporate Planning and Budgeting organization as Staff Financial Analyst of Strategic Initiatives and was promoted to Manager of Strategic Initiatives in 2007. In this role, I was responsible for working with AEPSC leadership in developing AEP's strategic plan and other strategic studies and analysis. In 2009, I transferred to AEP's transmission business unit as Manager, Transmission Strategy and Business Development where I was responsible for coordinating activities associated with the operations of the AEP transmission companies and for budgeting and financial analysis for the AEP transmission organization. In 2012, I was promoted to Director of Competitive Transmission Development for AEP's affiliate company Transource Energy, LLC. There, I was responsible for securing competitive transmission projects within the PJM and MISO regions. In 2018, I was named Director, FERC and RTO Strategy and Policy, responsible for federal and regional policy matters impacting AEP's transmission and generation businesses. In March 2023, I was promoted within the same group to my current position.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS MANAGING DIRECTOR – TRANSMISSION RTO POLICY?

A. I lead a team that is responsible for the development and advocacy of AEP's and its subsidiaries' strategies and positions in their respective Regional Transmission Organization ("RTO"), including PJM, regarding policy matters impacting the transmission and generation functions. This includes working closely with AEP operating companies and other AEP leadership to determine the impacts of and develop positions regarding potential policy changes. My team is deeply engaged in the stakeholder process ranging from technical working groups to the most senior standing committees.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have testified before the Arkansas Public Service Commission and the Indiana Utilities Regulatory Commission. Additionally, I have submitted direct testimony in Kentucky Power's current base rate case (2023-00159).

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides a high-level factual background regarding the benefits to Kentucky Power's customers resulting from its membership in the PJM Interconnection, L.L.C. ("PJM") regional transmission organization in response to section 6(l) of the topics required by the Commission's order establishing these proceedings.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I provide with my testimony the following two documents: **Exhibit JDB-1** is a PJM document titled "PJM Value Proposition", which summarizes and quantifies several fundamental benefits to Kentucky Power's customers and the other customers served by utilities in the PJM service footprint resulting from PJM's operation of the high-voltage power grid (i.e., electric transmission system), wholesale electricity markets, and PJM's transmission planning process.

Exhibit JDB-2 is a PJM document titled "The Benefits of the PJM Transmission System", which in more detail quantifies the value of new and existing transmission facilities planned, coordinated, and operated by PJM for the benefit of customers of utilities members of PJM, including the customers of Kentucky Power.

Q. HAS KENTUCKY POWER CONDUCTED A COST-BENEFITS ANALYSIS OF ITS PARTICIPATION IN PJM?

A. The Company has not performed a quantitative analysis over any particular time period to measure or estimate the specific benefits that Kentucky Power's customers receive directly and indirectly from Kentucky Power's participation in PJM.

The benefits of PJM participation, however, are well-documented by analysis from PJM itself. In summary, PJM has explained that at the time of record development in these proceedings, PJM's markets and services provide PJM-wide annual estimated customer benefits of between $3.2 and $4 billion. This figure includes: (1) $300 million in annual reliability savings; (2) $1.2 to $1.8 billion in annual savings related to lower capacity reserve margins and competition from alternative resources; (3) $1.1 to $1.3 billion in annual savings from integrating more efficient resources; and (4) $600 million in annual energy production cost savings because of PJM's expanded generation dispatch footprint.[1]

PJM has explained that these benefits are driven in no small part because of its broad and stable membership base, which has included Kentucky Power since the Commission authorized Kentucky Power to join PJM in 2004. For a more detailed explanation of these benefits and their drivers, please refer to the two public PJM documents attached to my testimony as Exhibit JDB-1 and Exhibit JDB-2.

[1] See Exhibit JDB-1 at 1-3.

Q. DO KENTUCKY POWER AND ITS CUSTOMERS BENEFIT FROM KENTUCKY POWER'S PARTICIPATION IN PJM?

A. Yes. By way of example, Kentucky Power's participation in PJM gives it access to PJM's transmission service, which in turn avails Kentucky Power of the benefits of participation in all aspects of PJM. This includes the benefits resulting from having access to the whole transmission system over which PJM has functional control, and to all the markets administered by PJM, including energy and capacity markets.

To have access to the PJM energy and capacity markets that Kentucky Power requires to serve its customers, Kentucky Power depends on transmission facilities it does not own, located in PJM both within and outside the AEP Zone. Without access to use these transmission facilities, Kentucky Power would be constrained to rely on more limited generation resources or on energy and capacity contracts that undoubtedly would embed a cost for using and having access to the infrastructure necessary to transmit power from where it is generated to the load centers in Kentucky Power's territory. Access to these facilities is necessary for Kentucky Power's customers to benefit from the economic efficiency, flexibility, resilience, reliability, and depth of service that are the hallmark of an electric regional transmission organization.

Kentucky Power's customers receive the benefits of Kentucky Power's participation in PJM in a wide variety of ways, including enhanced transmission service reliability, efficiency, and cost-effectiveness resulting from coordinated regional transmission planning and operation, greater access to low-cost generation, efficient energy, capacity and ancillary services markets (where Kentucky Power at different times has participated both as a buyer and a seller), and mitigated costs and risks associated with real-time spot market trading, hedging, and day-ahead pricing, among many other benefits.

Q. DOES KENTUCKY POWER'S USE OF THE TRANSMISSION SYSTEM OUTSIDE OF KENTUCKY PROVIDE ADDITIONAL ASSURANCES THAT CUSTOMERS WILL HAVE ACCESS TO CAPACITY NEEDED TO SERVE CUSTOMERS?

A. Absolutely. Specifically concerning its access to capacity resources, Kentucky Power's access to the PJM transmission system, and particularly to the transmission facilities in the AEP Zone, provide Kentucky Power with ample flexibility to elect to continue to satisfy its capacity requirements under PJM's FRR alternative, or elect in the future, depending on market conditions and an evaluation of relative risks, to instead participate in the RPM capacity market. Such flexibility would simply not exist if Kentucky Power had no access to the transmission facilities in the AEP Zone and beyond in PJM.

IV. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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jburkholder@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
October 02, 2023 12:06:45 -8:00 [D5FD8862B52A] [167.239.221.107]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Joshua D. Burkholder, being duly sworn, deposes and says he is the Managing Director of Transmission RTO Policy, for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Joshua D Burkholder

Joshua D. Burkholder

Commonwealth of Kentucky)
) Case No. 2023-00008
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Joshua D. Burkholder, on October 2, 2023

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission# KYNP71841
My Commission Expires May 05, 2027

Notary Public

Notarial act performed by audio-visual communication

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

PJM Value Proposition

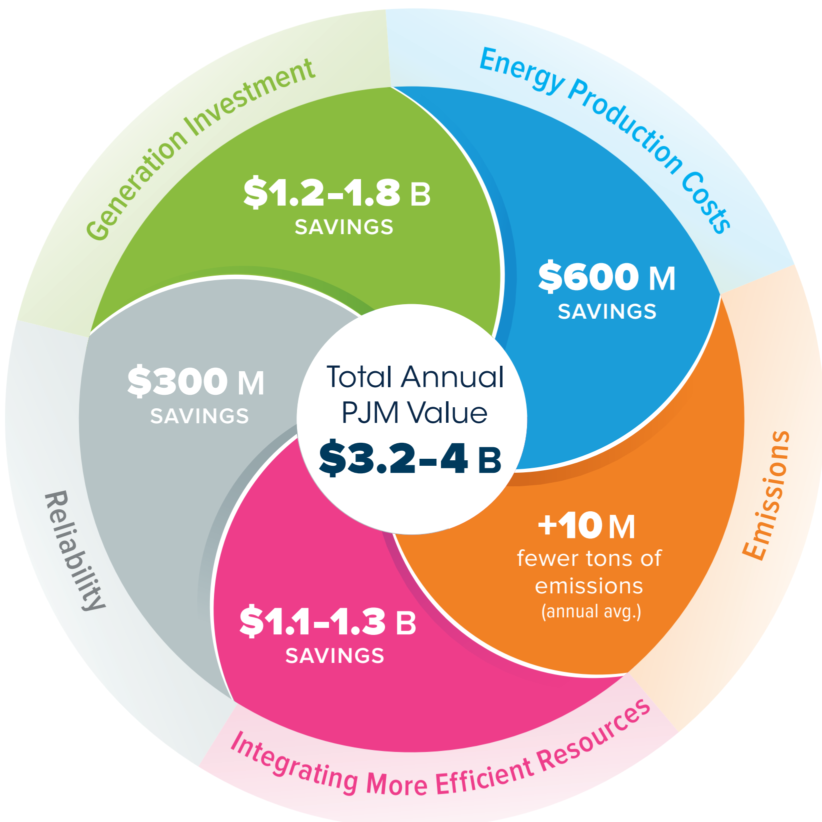
PJM Interconnection's operation of the high-voltage power grid, wholesale electricity markets and its long-term planning process provide significant value to the 65 million people in the region it serves.

PJM operations, markets and planning result in annual savings of $3.2 – 4 billion. These savings represent the vital functions that PJM provides and that lead to less cost to consumers:

- Ensuring reliable power 24 hours a day, 7 days a week
- Providing capacity for the future and reserves for emergencies

- Managing generation and other resources in real time to meet consumer demand
- Procuring specialized services that protect the stability of the grid

- Lowering emissions by encouraging generator efficiency
- Offering additional benefits including training, compliance audits and knowledge sharing



All numbers are estimates.

Reliability

Transmission enhancements in PJM are expected to reduce costs by nearly $300 million a year by alleviating congestion.

Regional Planning Efficiencies

PJM's regional planning process assesses the need for transmission upgrades to ensure reliability, increase efficiency and support public-policy goals.

PJM's large footprint makes the transmission planning process more effective by considering the region as a whole, rather than by individual states or separate transmission-owner territories, in determining transmission needs.

Investing in the transmission system can increase its ability to move more power, which can decrease congestion costs. ***Transmission enhancements in PJM are expected to reduce costs by nearly $300 million a year by alleviating congestion.***

$300 M
SAVINGS

Generation Investment

This results in savings of $1.2–1.8 billion.

Lower Reserve Margin and Competition from Alternative Resources

The fact that PJM plans for resource adequacy over a large region results in a lower reserve margin than otherwise would be necessary.

Resource adequacy means having enough generating resources available to meet the demand for electricity, plus a reserve margin to cover emergencies.

There is considerable diversity in electrical use patterns in the large PJM footprint; not all areas peak at the same time of the year.

As a result, resources in one area of the system are available to help serve other areas at peak times, and a smaller reserve is required.

In addition, the large and varied resource fleet across the entire PJM region spreads the generator outage risk across a larger collection of generators, improving reliability.

PJM's Reliability Pricing Model capacity market promotes competition between traditional generation and alternative supply resources such as demand response. With more cost-effective alternatives to maintain adequate power supplies, less investment is needed in new generation. ***This results in savings of $1.2–1.8 billion.***

$1.2–1.8 B
SAVINGS

Integrating More Efficient Resources

More efficient units demonstrate a savings of $1.1–1.3 billion a year

Replacement of Less Efficient Resources

PJM's efficient generation interconnection process, combined with the competitive RPM capacity market, has enabled less efficient generation resources to retire and to be replaced with more efficient, less costly, plants.

From the annual RPM auction from 2011 through 2018, nearly 30,000 megawatts of new, increasingly efficient natural gas combined-cycle generation either has already commenced operation or is committed to be built through the RPM auctions.

These resources operate more efficiently, with lower heat rates and in most cases lower fuel costs, than the older, less efficient resources they have replaced through retirement.

Simulations of the increased cost that would be associated with continuing to operate the retired resources instead of the new, more efficient units demonstrate a ***savings of $1.1–1.3 billion a year.***

$1.1-1.3 B
SAVINGS

Energy Production Costs

Operating the larger market creates production cost savings of $600 million a year

Expanded Dispatch Area

PJM's dispatch process enables energy to be exchanged economically and automatically when less expensive resources in one area can be used to meet consumer electricity demand in another area.

Prior to the expansion of the PJM footprint more than a decade ago, energy usually was exchanged between areas only when energy sales transactions were scheduled between two suppliers.

Without the operation of the centralized market structure that exists today, economic energy exchanges occurred much less frequently and efficiently.

Simulations of the economic dispatch and energy exchange before and after the PJM market expansion show that operating the larger market creates production cost ***savings of $600 million a year.***

$600 M
SAVINGS

Emissions Savings

Annual average reduction of more than 10 million fewer tons of CO_2 emissions

PJM contributes to climate policy goals while maintaining reliability through the efficient operation of the wholesale power markets.

Competition in organized markets results in greater energy efficiency. Efficient plants burn less fuel and produce fewer emissions. Since 2005, PJM has seen an overall reduction in emissions of approximately 30 percent as a result of an increase in wind generation, other renewables and the inexpensive shale gas boom in the PJM region. This translates to an ***annual average reduction of more than 10 million fewer tons of CO_2 emissions.***

+10 M
Fewer Tons of Emissions
(annual avg.)

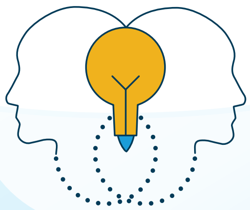
Additional Benefits

PJM is a source of neutral, independent data, analysis, knowledge and expertise for the industry, lawmakers and regulators. In this role, PJM facilitates information sharing and informs decisions that help strengthen the grid and drive the power industry forward.

Training

PJM is dedicated to continuing education and providing training for industry professionals.

- PJM offers more than 160 training days a year, attended by 7,000 trainees, including 1,000 member company operators
- PJM awards 45,000 NERC continuing education hours annually
- 17,000 of the continuing education hours are simulation training, which prepares trainees for real-world experiences in system and market operations



Compliance Audits

As a regional transmission organization, PJM is audited periodically (every three years) by ReliabilityFirst, NERC and SERC Reliability Corporation. These audits review PJM's compliance with Critical Infrastructure Protection standards, operations and planning standards. The approximate cost for PJM to complete an audit is $2 million. Because PJM is registered as the transmission operator and is audited by ReliabilityFirst, NERC and SERC, individual transmission owners do not have to participate in the audits on their own. The cost for an audit for a transmission owner would vary but could total more than $2 million for one individual transmission owner alone.

Innovation

PJM provides opportunities and a marketplace for innovators – such as PJM member organizations, research and academic institutions, and industry experts – to strengthen and enhance the power grid. PJM also conducts in-depth research and produces detailed white papers on various topics to promote information and knowledge sharing.

PJM supports and facilitates emerging technology programs to integrate batteries, electric vehicles and other power storage into PJM's markets, as well as ongoing initiatives to explore how the burgeoning development of distributed energy resources can be integrated more effectively with grid operations.

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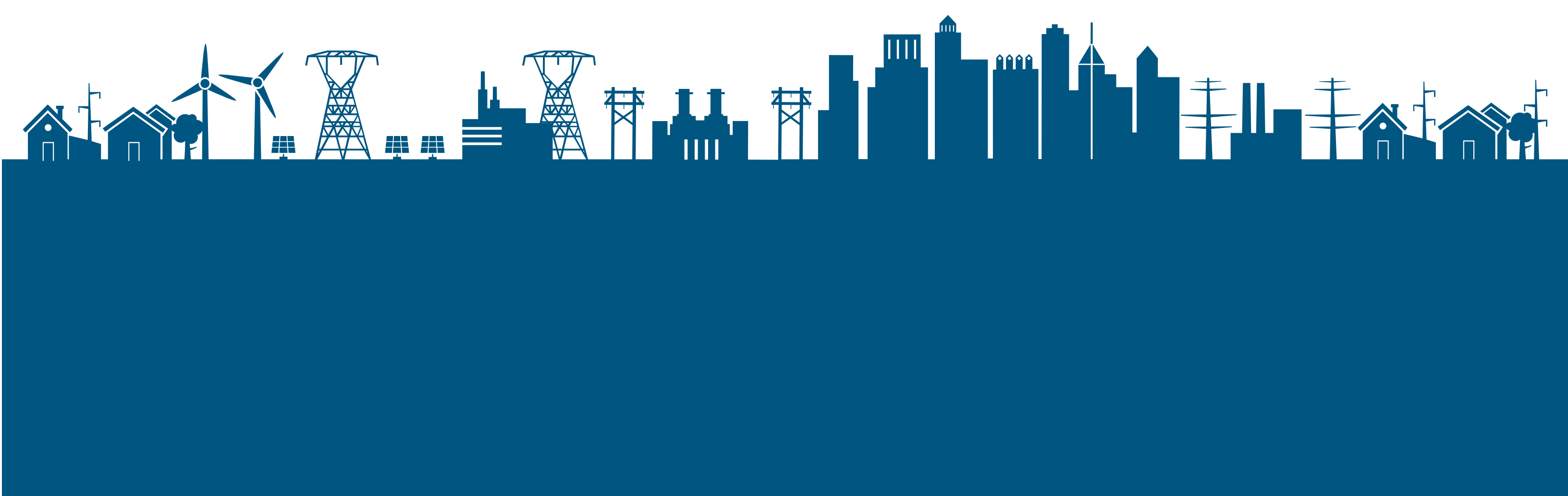
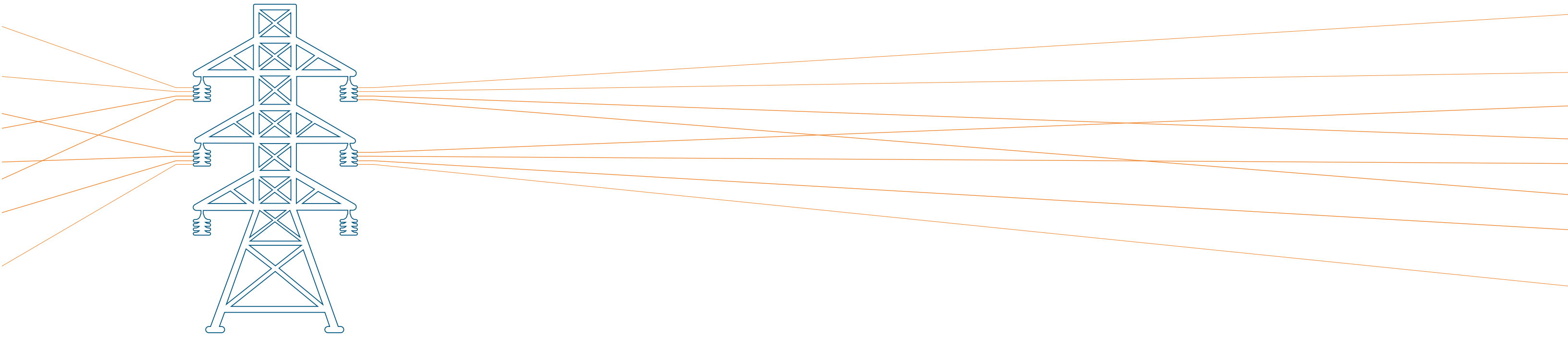
Working to Perfect the Flow of Energy

THE BENEFITS OF THE PJM TRANSMISSION SYSTEM

PJM INTERCONNECTION

April 16, 2019





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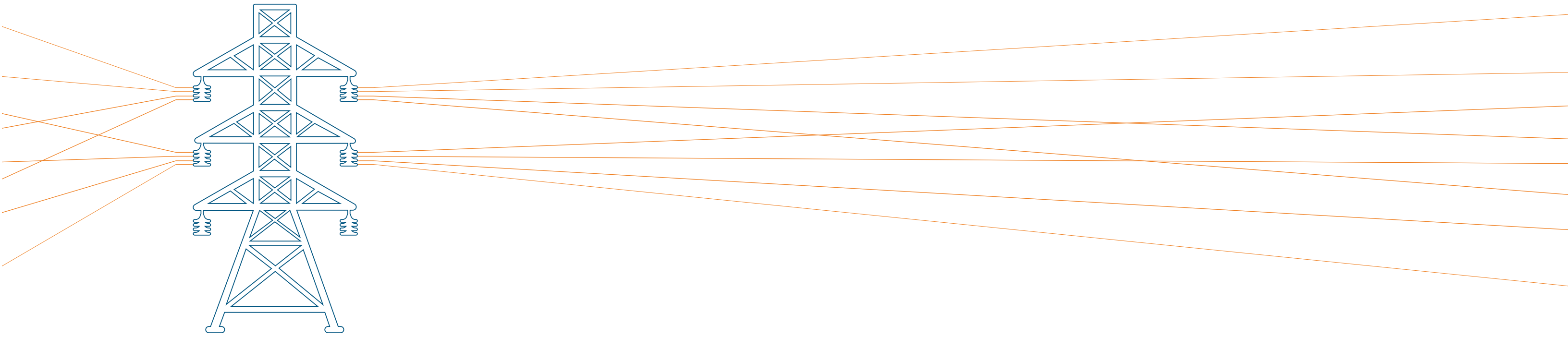
Errata – April 30, 2019

Apr. 30, 2019:

On page 12, Fig. 4, the “Supplemental” and “Network Upgrades” labels were swapped.

By the Numbers...

- PJM's competitive markets, the largest in the world, are enabled by more than 84,200 miles of transmission at 100 kV and above.
- Transmission lines link PJM zones together, allowing them to share capacity and leverage load diversity to reduce the need for additional generation by up to $3.78 billion annually.
- Simulating capacity market auction results without transmission tie lines to adjoining regions yielded an increase in total payments to capacity resources of $1.7 billion in the 2020/2021 auction and $1.3 billion in the 2021/2022 auction. This translates to 15 percent and 19 percent savings, respectively.
- A robust transmission system lowers the net costs of electricity to consumers by allowing the next most-cost-effective megawatt to be dispatched. This reduces overall production costs for generators and the payments that the end users of electricity make.
  - PJM transmission assets enable competition among power producers by providing access to PJM's wholesale markets. In 2018 alone, PJM billings totaled $49.8 billion for 806,546 GWh of energy bought and sold within PJM's Energy Market.
  - Transmission enhancements in PJM are estimated to reduce costs to customers by more than $280 million a year by alleviating congestion.
  - New interregional transmission assets will produce estimated congestion savings of more than $100 million in the first four years of commercial operation alone.
- Some 20 percent of new transmission assets continue to ensure reliability throughout an ongoing, historic and unprecedented generation shift driven by public policy and fuel economics.
  - From 2011 through 2018, 31,722 MW of generation has retired, including more than 24,000 MW from 125 coal-fired units, some more than 45 years old.
  - Retiring units have been replaced by more than 38,000 MW of new resources, including more than 29,500 MW of additional Marcellus and Utica shale natural gas-fired generation and 5,910 MW of renewable wind and solar generation.
  - Today, PJM's generation mix is 30 percent less carbon-intensive than 10 years ago. On average, producing one megawatt of power in PJM emits 13 percent less carbon dioxide than 10 years ago and 28 percent less than in 2005.
- At PJM's direction, transmission owners have invested more than $1.3 billion in reactors and static VAR compensators between 2008 and 2018 to reduce the more-expensive generation required to help absorb excess reactive power. This ensures that voltages remain within established limits, typically during periods of low customer demand.
- Transmission helps to maintain reliability across the PJM region – and with neighboring systems – during periods of extreme weather and sudden loss of large generators, when reliable power delivery is needed the most.
- The average operating margin – maneuvering room before hitting a limit – on PJM's 10 internal transfer interfaces more than doubled, from 1,482 MW in 2011 to 3,016 MW in 2018, in part due to new transmission assets.



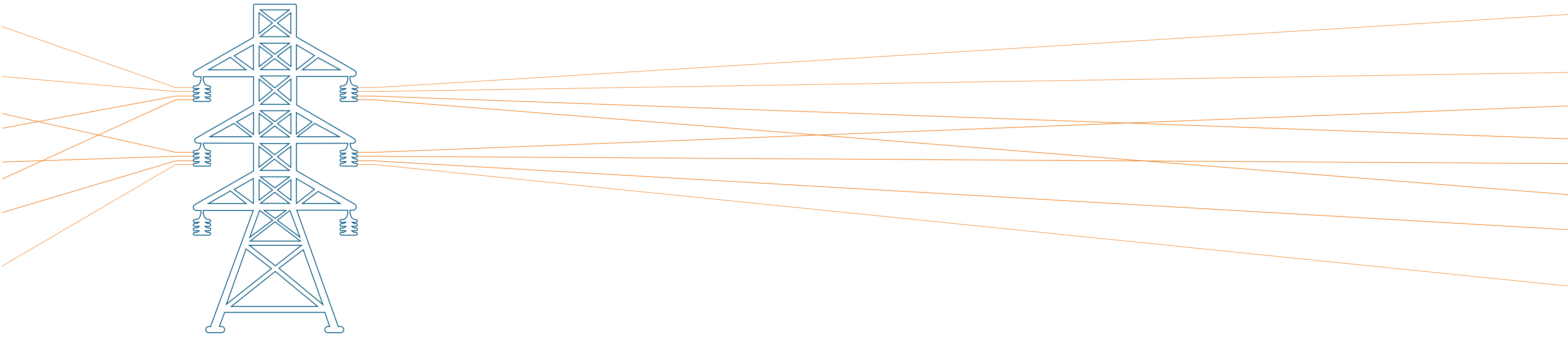
Preface

The goal of this white paper is to quantify the value of new and existing transmission equipment, lines and other assets for PJM Interconnection stakeholders and other engaged parties. This paper is a follow-up to the January 28, 2019, briefing paper, The Value of Transmission, which was a preview of this more expansive treatment of the subject.

The quantitative benefits discussed in this document are based on case studies, analysis and data from across PJM's Planning, Operations and Markets divisions. Each division has provided valuable insights and data to help value the reliability, economic and public policy goals that transmission enables. The majority of this paper focuses on data and narrative about the value of transmission assets.

While PJM's regional planning processes and transmission owner asset management processes are key to transmission development, the focus of this paper is on quantifying the benefit of the assets themselves. Information on these important processes is provided in appendices.

This paper offers observations that summarize transmission value. It does not, and is not intended to, take positions or draw conclusions on issues under discussion in the PJM stakeholder process, at the Federal Regulatory Energy Commission or in state legislatures and utility commissions.



Executive Summary

Transmission Delivers Power and More

"What am I getting for my transmission investment dollars?" In recent years, this question has been on the minds and agendas of state legislatures and utility commissions, consumers and other PJM Interconnection stakeholders. It's a natural question. Today, transmission is constructed and improved for different reasons than 10 years ago. For most of the history of the transmission system, new projects were driven by two things: growth in the demand for electricity from consumers (also called "load") and requests from new generators to connect to the grid, which often require new transmission lines to reach load centers.

The benefits of the transmission system itself and the dollars invested in it extend well beyond delivering power over high-voltage transmission lines. In this paper, PJM quantifies the benefits and drivers of new transmission:

- **Ensuring reliability** – keeping the lights on
- **Keeping costs low** – delivering the lowest cost energy to customers through wholesale markets
- **Supporting public polic**y – helping bring to fruition state renewable mandates and federal emission mandates

Load is no longer growing at the 1 percent to 3 percent pace it once was. Now, load growth rates of 0.5 percent and lower are not unusual. Instead of load, transmission investment drivers now include shifting generation resources from coal to gas and renewables, aging infrastructure repair or replacement to maintain reliability, supporting public policy goals (environmental mandates, for example), and ensuring lower-cost energy flows to everyone in PJM by mitigating congestion.

The Value of Transmission

Electricity is a real-time, on-demand commodity used virtually the moment it's created. Like any commodity, it must be delivered from the point of production – a generator – to the point of consumption – our homes and businesses. Transmission lines are the "highway" across which electricity is delivered. The high-voltage transmission network is regionally operated and planned by PJM to ensure reliability at lowest cost. Transmission facilities deliver the power that is vital to our economy, security and overall society. But simply delivering power is not enough. Reliability, resilience and cost effectiveness are equally important. And through preventing loss of power, transmission assets provide the backbone for economic growth and societal well-being, such as access to cleaner, greener generation resources.

Ensuring Reliability at the Lowest Cost

Transmission has enabled the market integration of seven systems into PJM since 2002, increasing reliability and capturing ever larger economies of scale. Load diversity[1] alone across PJM has increased from 1 percent to 3.5 percent since PJM's first market integration in 2002. For perspective, the current load diversity across PJM's original footprint is 1,213 MW whereas as the load diversity across the current PJM footprint is 5,980 MW. This 4,767 MW increase enhances reliability, as it allows zones with excess capacity during periods of peak customer demand to export capacity to zones in need. This reliability benefit is enabled by the 325 inter-zonal transmission lines connecting each transmission owner (TO) zone to adjoining ones.

This benefit, coupled with a generation fleet made up of units with diverse sizes and outage rates, has reduced the capacity reserve levels needed to supply customers. For example, the generation reserves required for the original Mid-Atlantic area of PJM, before all market integrations, were approximately 22 percent. Today the requirement is 15.7 percent. Transmission ties between zones mean that fewer megawatts of generation are needed across PJM to serve load reliably. PJM studies indicate that this has an economic benefit, reducing the need for additional capacity by an estimated $3.78 billion annually, discussed further in **Section 2**.

Equal Access to Lower-Priced Power

Transmission enables the lowest-cost power to reach the greatest number of people. PJM operates the grid by scheduling and directing the lowest-cost power resources to generate electricity first, incrementally adding more expensive resources as they're needed and saving the highest-cost resources for relatively brief periods of peak customer demand.

Transmission assets tie PJM zones together. These assets enable competition among power producers by providing access to PJM's wholesale markets for capacity, energy and ancillary services. In 2018 alone, PJM billings totaled $49.8 billion for 806,546 GWh of energy bought and sold within the PJM Energy Market. A robust transmission system lowers the net costs of electricity to consumers by allowing the next most-cost-effective megawatt to be dispatched. This reduces overall generator production costs and payments made by load.

Since 2002, PJM has added seven transmission zones to its original footprint, enabling the addition of 112,000 MW of generation and 95,000 MW of peak customer demand. This has increased competition in wholesale power markets and provided lower prices to consumers. PJM transmission ties with adjoining power systems provide market access to other adjoining wholesale energy markets such as New York, New England and the Midwest.

Throughout the year, market economics can shift (even from hour to hour) across all 8,760 hours of a year. When the transmission system is constrained and power cannot flow freely, operators must reroute the power flow by dispatching higher-cost generation. This yields less-efficient production of electric power and can increase the cost to consumers. Investing in the transmission system can increase its ability to move more power, decreasing congestion costs and saving consumers money. Transmission enhancements in PJM are expected to reduce costs to customers by more than $288 million a year by alleviating congestion, discussed further in **Section 5**.

Transmission Enables Economic Growth[2]

As many economists and state governmental officials have noted, lower electricity costs drive regional economic growth, making local economies more attractive to industrial and commercial businesses and spurring investment. Lower household electricity bills increase disposable income, which increases the demand for goods and services. Several related recent reports speak to the fundamental links between transmission investment and economic growth.

1 Load diversity is the sum of all zonal non-coincident megawatt annual peaks minus the PJM coincident megawatt annual peak.

2 WIRES, https://wiresgroup.com/new/wires-library/wires-reports.

Enabling Day-to-Day Reliability

At its most fundamental, the PJM transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed.

Operational Flexibility

At every moment, 24 hours a day, 7 days a week, system operators ensure that power continues to flow to customers. The more robust the transmission network is, the greater the system margin.[3] For instance, the average margin in PJM across all ten internal transfer interfaces[4] was 1,482 MW in 2011, which more than doubled to an average margin of 3,016 MW in 2018, in part due to new transmission assets, as discussed in **Section 4**. Drawing a comparison to the interstate highway system, margin gives operators room to maneuver. System margin allows operators to address unexpected system events like loss of generation or loss of another transmission facility.

Solving Aging Infrastructure Issues

Transmission facilities continue to age. Some assets date to the 1960s or even earlier. 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. Asset owners are identifying serious structural deterioration leading to system enhancements to avoid facility failure and customer service interruptions as discussed in **Section 6**. These replacements have economic benefits as well and have, in certain instances, reduced average annual congestion costs by an order of magnitude or more.

Asset modernization goes beyond simple replacement. Such projects have provided the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when the original facilities were built, which is discussed further in **Section 6**.

Access to Support in Emergency Conditions

Tie lines with adjoining systems enable neighboring systems to help one another during emergencies. The impact of extreme peak loads during hot summers and frigid winters or the sudden loss of large generators can be minimized by relying on access to generating resources outside of PJM, enabled by interregional agreements and operating procedures with adjoining systems. For instance, established shared generation reserve procedures with the Northeast Power Coordinating Council (NPCC) allow either party to request reserves from the other for a sudden loss of generation greater than 500 MW. PJM and NPCC assisted each other 57 times during 2018 alone, as discussed in **Section 4**.

Grid Resilience

Resilience enables the continuous delivery of electric power to customers through times of unusual and extreme levels of equipment or fuel supply disruptions. These can be caused by a variety of extreme conditions, including weather and fuel delivery system failures. Planning for these events and cost-effectively enhancing system resilience could become a future driver of new transmission investment, as discussed in **Section 6**.

3 Margin, in this context, essentially means the difference between the level of power flowing on one or more transmission facilities at a given instant and the limit of that power flow. Said another way, it's extra room available for additional electricity to flow through the transmission system in case of emergency.

4 PJM's ten internal transfer interfaces, as discussed in **Section 4**, are monitored to ensure that power does not exceed limits that could lead to voltage instability for defined system contingencies.

Ensuring Reliability in a Historic Generation Shift

The grid continues to support a historic and unprecedented generation shift driven by public policy and fuel economics, as discussed in **Section 3**. Coal-fired generation is retiring and being replaced by natural gas-fired and renewable generation. From 2011 through 2018, 258 generating units totaling 31,722 MW across all fuel types retired from service. More than 24,000 MW of those retirements were from 125 coal-fired units, some of them more than 45 years old.

Over the same period, retiring units were replaced by more than 38,500 MW of new generation. Another 16,172 MW is under construction and 87,680 MW is actively under study in PJM's generation interconnection process. Between 2011 and 2018, transmission system enhancements in PJM have enabled the interconnection of more than 29,500 MW of additional natural gas-fired generation and 5,910 MW of renewable wind and solar generation. Today, PJM's generation mix is 30 percent less carbon-intensive than 10 years ago. On average, producing one megawatt of power in PJM emits 13 percent less carbon dioxide than 10 years ago and 28 percent less than in 2005.

The impact of these changes to PJM cannot be overstated. Neither can the role that transmission has played in allowing this shift occur without compromising reliability:

- A robust transmission system enables new technologies – like wind and solar facilities – to site, configure and operate facilities reliably.
- New transmission assets maintain grid reliability, permitting older generators to retire without causing transmission line overloads or other reliability criteria violations.
- New generation powered by natural gas and renewable fuels relies on new transmission assets in order to sell reliable, economic power into PJM markets.

In addition, the operational flexibility provided by new transmission assets is responsible for encouraging the development of new generation in PJM's footprint, particularly generation fueled by natural gas from the Marcellus and Utica shale. By enabling more generators to compete, the transmission system helps ensure that the lowest-cost generation serves customer load, no matter where it is in the PJM footprint.

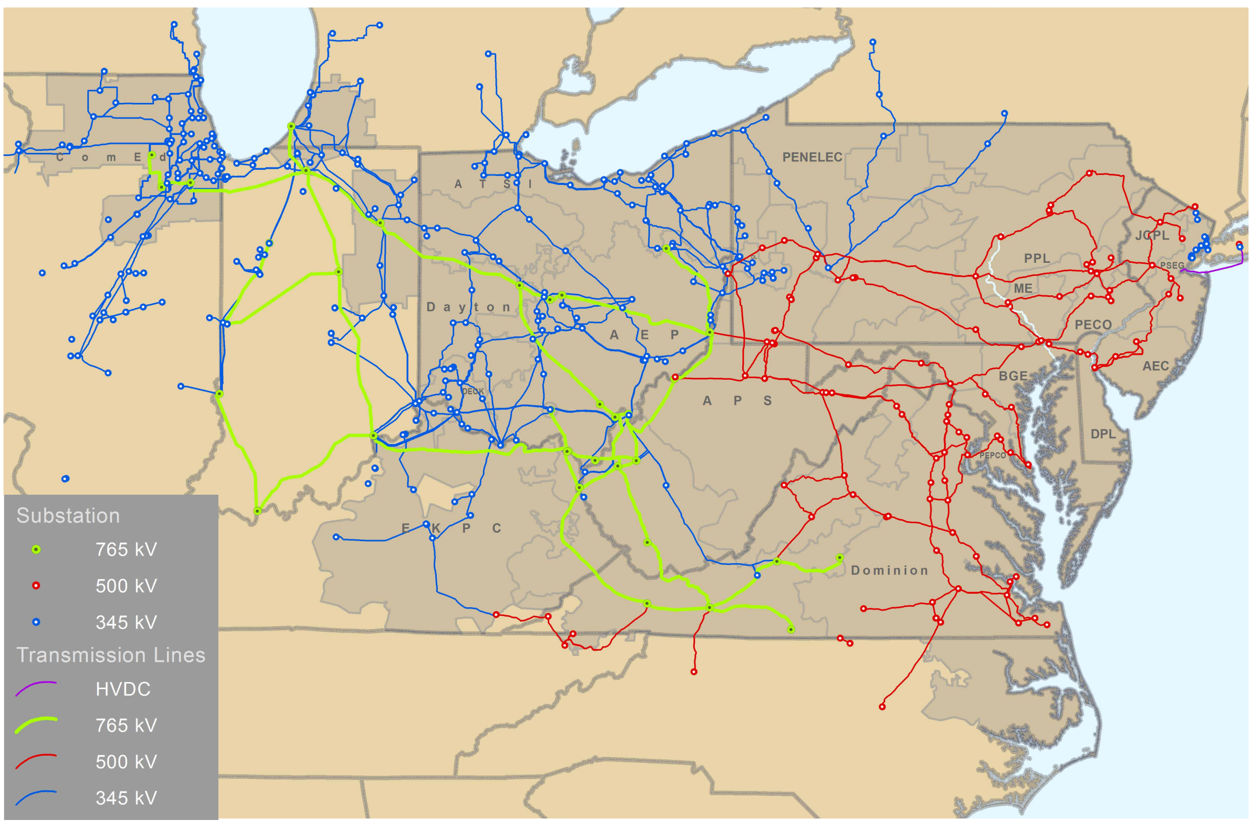
Across the Nation

PJM is not alone in its need for new transmission assets, as discussed in **Section 1**. Since 2010, historical and projected transmission investment in the U.S. has continued to grow in independent system operator/regional transmission organization (ISO/RTO) footprints and utilities that are not part of such entities. Available data indicates that, in light of its geographic scope, PJM may outspend other areas of the country in absolute dollar terms, but on a megawatt load-weighted basis, transmission investment in PJM is about average when compared to other ISO/RTOs.

Section 1 Economies of Scale — the Regional Value of Transmission

PJM oversees the round-the-clock generation and delivery of electricity to more than 65 million people in 13 states and the District of Columbia. This requires the careful planning of transmission system enhancements to ensure the reliable delivery of electricity now and in the future. The PJM transmission system that enables power to flow freely throughout PJM is shown in **Map 1.**

Map 1: PJM Backbone Transmission System



PJM directs the operation of more than 84,200 miles of transmission lines across 369,089 square miles of territory, interconnecting with more than 180,000 MW of power generation. Within PJM, 325 transmission tie lines connect each TO zone to adjacent zones, permitting the free flow of power between them. This essential aspect of the PJM grid gives rise to the benefits of shared capacity, power markets and mutual support under stressed system conditions – extreme weather, for example.

Those benefits are amplified when the 212 transmission tie lines between PJM zones and systems adjoining PJM[5] are also considered. While PJM coordinates the flow of electricity on the transmission system, it works cooperatively with the transmission-owning utilities that operate and maintain the equipment that makes up the transmission system, such as high-voltage power lines and substations. PJM is authorized by the Federal Energy Regulatory Commission (FERC) to oversee the grid in its region, bringing independence to operating and planning the infrastructure that is built and owned by the TOs.[6]

The transmission system is similar to the interstate highway system in both the value it brings to society and the cost to build and maintain it. Though building and maintaining such infrastructure can be costly, the result is a system that works around the clock and is designed and maintained to serve the public's demand for safe, reliable electric power at the flip of a switch. Like the interstate highway system, everyone benefits from the transmission system upon which everyone relies for day-to-day livelihoods, crucial goods and services, and emergency services.

PJM's FERC-approved cost allocation procedures[7] reflect this regional "everyone benefits" reality. The cost for new reliability-driven transmission assets – approved by the PJM Board of Managers out of PJM's regional transmission expansion process (RTEP) – that will operate at 765 kV and 500 kV or comprise double-circuit 345 kV construction are allocated 50 percent via load-ratio share across all TO zones and 50 percent via distribution factors based on the impact of a new asset. The socialized component of the allocation acknowledges that a definitive benefit from the elimination of a reliability criteria violation accrues to all consumers of electricity across the PJM footprint. Similarly, Board-approved market-efficiency-driven[8] RTEP projects that will operate at 765 kV and 500 kV, or comprising double-circuit 345 kV construction are allocated 50 percent via load-ratio share and 50 percent via zonal benefit from decreased load payments.

Without continued transmission investment to keep pace with the needs of a growing modern society, new internet, transportation and other technological advancements would be impossible. Customers and generation developers alike rely on investments made in transmission infrastructure. And while initial capital costs can be significant, new transmission infrastructure provides reliability and economic value throughout infrastructure life spans that regularly exceed 50 years.

How Transmission Needs Are Identified

Transmission continues to evolve as grid and consumer needs change. Maintaining a reliable and efficient transmission system in this fluid environment requires extensive planning, coordination, communication and transparency. PJM's comprehensive RTEP process – described in **Appendix A** – identifies the need for changes and additions to the system up to 15 years in the future. The long planning horizon gives the developers who take on these projects time to marshal the necessary resources and gain state and local approvals to build the infrastructure.

5 Including the Midcontinent System Operator (MISO), the New York System Operator (NYISO), TVA, Duke Energy, OVEC and LGE/Kentucky Utilities.

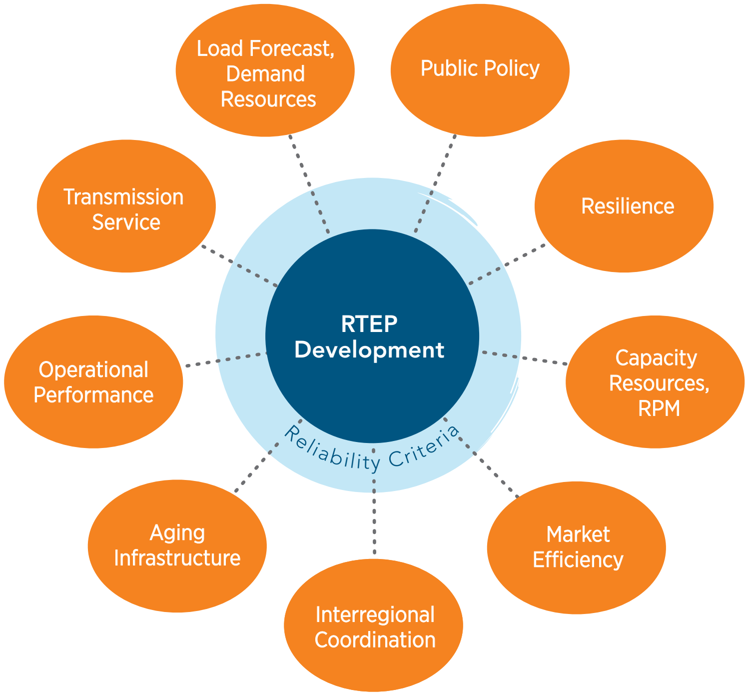
6 This relationship is codified in several organizing agreements: Transmission Owners Agreement (TOA), PJM Operating Agreement (OA) and PJM Open Access Transmission Tariff (OATT or Tariff). These agreements can be found on the PJM website.

7 Additional details of PJM's RTEP process cost allocation procedure for reliability driven transmission enhancements can be found in Attachment A of PJM Manual 14B: PJM Region Transmission Planning Process: https://www.pjm.com/-/media/documents/manuals/m14b.ashx.

8 Details of PJM's RTEP process cost allocation procedure for market efficiency driven transmission enhancements can be found in Section (b)(v) of Schedule 12 of the OATT and Section 1.5.7(b) of the OA.

PJM's regional scale makes the transmission planning process more efficient by considering the region as a whole, rather than as individual states or separate transmission zones. Transmission system enhancements are driven by a variety of evolving and interrelated industry, market and public policy issues (see **Figure 1**).

Figure 1: Transmission System Enhancement Drivers



The RTEP process ensures that the transmission system complies with national and regional reliability criteria, which are intended to prevent overloaded facilities and potential loss of delivery (also called lost load – in other words, brownouts or blackouts). The North American standards for thermal, reactive, stability short-circuit, and other system requirements are set by the North American Electric Reliability Corporation (NERC), under authorization from FERC.

In order to evaluate the grid for compliance with NERC and regional criteria, PJM has developed and implemented a number of reliability-focused tests with this goal in mind, as described in **Appendix A.** These tests are conducted under simulated emergency conditions in which the grid is stressed to ensure power can be delivered when it is most needed and when local generation is insufficient to provide it.

PJM is required by NERC to plan and operate transmission facilities at 100 kV and above as well as those lower voltage facilities, at the request of the transmission owner. In response to identified regional reliability, market efficiency or public policy needs, PJM staff recommends projects to include in the RTEP, which then must be approved by the PJM Board.

New transmission projects – whether directed by PJM or by TOs as supplemental projects – are built to serve one or more purposes:

- **Increase power-flow capability.** New lines and transformers, existing line reconductoring and bus reconfigurations
- **Provide voltage support and improve generating unit stability.** New devices like shunt capacitors and static VAR compensators
- **Ensure safe transmission line operation.** New substation equipment like circuit breakers, switches, relay protection and control equipment, and instrumentation

Frequently, constructing new facilities to serve one purpose addresses others as well.

For perspective, transmission line capabilities typically have the following ranges:

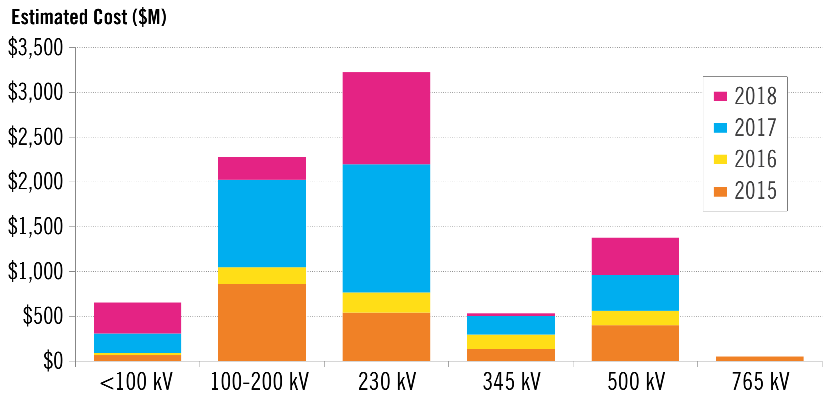
VOLTAGE CLASS	POWER (MVA)	CURRENT (AMPS)
765 kV	4,000	3,079
	5,400	4,157
500 kV	2,500	2,887
	3,500	4,041
345 kV	1,000	1,673
	2,000	3,347
230 kV	420	1,054
	1,250	3,138

Regional Transmission Investment

When the RTEP process began in 1997, transmission enhancements ensured that the growth in customer demand could be met and that new generating resources could be interconnected reliably. Customers could be sure enough power could reach them to keep the lights on, and new generation developers could be sure their new resources would not overload existing transmission lines and related facilities. Today, PJM's RTEP process is considerably more robust, and, as noted earlier, studies the interaction of many factors, including those arising out of public policy, market efficiency, interregional coordination and resilience (see **Figure 1**).

The dynamics driving transmission expansion have been shifting more rapidly in recent years. Relatively flat load growth, energy efficiency, security, generation shifts and aging infrastructure repair or replacement – among other issues – continue to move transmission needs away from new large-scale, cross-region backbone projects at higher voltages, as shown in **Figure 2.** Transmission investment in equipment that is 230 kV and below has focused on aging infrastructure replacement as well as upgrades to ensure reliability, improve transfer capability, and comply with local load-serving criteria. Often, system enhancements to solve one issue have helped address one or more other issues as well.

Figure 2: Approved Baseline Projects by Voltage (2015-2018)



Transmission projects fall into three categories:

- **Baseline projects:** Address reliability criteria violations including thermal, voltage, short-circuit and stability, as well as TO criteria violations,[9] including those violations driven by market efficiency and public policy.
- **Network projects:** Ensure new generation and merchant transmission projects interconnect reliably to the grid as submitted through PJM's interconnection queue.
- **Supplemental projects:** Identified by TOs to address their own local transmission reliability needs. These projects direct repairs or improvements to local transmission lines, equipment, address local operational issues, customer load growth and resilience. Even though the TO develops these projects, PJM reviews them to evaluate their impact on the regional transmission system, to coordinate necessary construction outages, and to implement necessary changes in PJM models and system operations.

Roughly 20 percent of all transmission projects approved by PJM since 1999 have enabled or will enable approximately 85,000 MW of new generation to connect to the system without causing transmission line overloads or other reliability criteria violations. Some 80 percent are baseline projects to ensure round-the-clock reliability and market efficiency. Others – known as supplemental projects – are identified by TOs to address local transmission needs. Regardless of how they are categorized, transmission projects that improve reliability can also improve economics and vice versa.

9 Per their respective annual transmission planning and evaluation reports filed with FERC in Form No. 715. Those criteria can be found on PJM's website.

Benefits by the Numbers: Transmission Investment

The benefits of the transmission system itself and the dollars invested in it extend well beyond delivering power over high-voltage transmission lines. In this paper, PJM quantifies the benefits and drivers of new transmission in terms of the following:

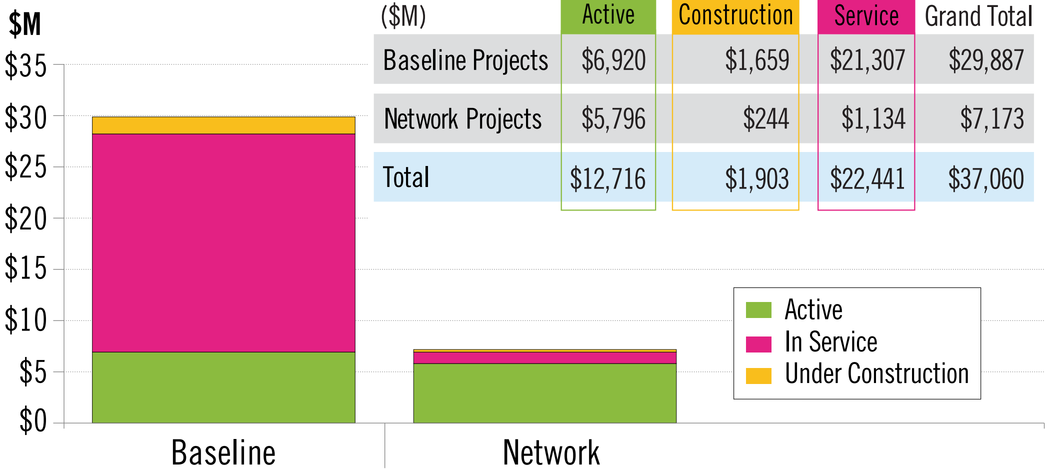
- **Ensuring reliability –** keeping the lights on
- **Keeping costs low –** delivering lowest-cost energy to customers through wholesale markets
- **Supporting public policy –** helping bring to fruition state renewable mandates and federal emission mandates

Investments in transmission system enhancements approved by the PJM Board since RTEP's inception in 1999 are summarized by their status[10] as of December 31, 2018, in **Figure 3.** The numbers provide a snapshot at a single point in time, as with an end-of-year balance sheet.

- Since 1999, the PJM Board has approved transmission system enhancements totaling $37.1 billion.
- $29.9 billion are baseline projects to ensure compliance with NERC, regional and local TO planning criteria and to address market efficiency congestion relief.
- $7.2 billion are network facilities to enable more than 85,000 MW of new generation to interconnect reliably.

Figure 3: Approved RTEP Projects (1999 - 2018)

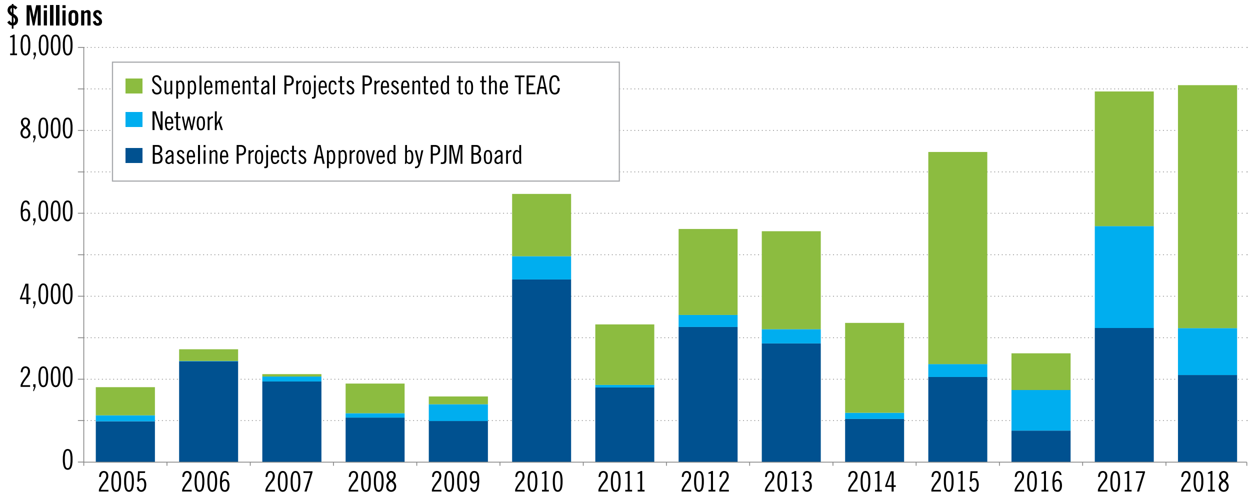
($M)	Active	Under Construction	In Service	Grand Total
Baseline Projects	$6,920	$1,659	$21,307	$29,887
Network Projects	$5,796	$244	$1,134	$7,173
Total	$12,716	$1,903	$22,441	$37,060



The baseline and network transmission investment approved by the PJM Board each year from 2005 through 2018 plus transmission owner supplemental project investment is shown in **Figure 4.**

10 Active baseline status means that the RTEP project has been approved by the PJM Board and awaits construction to begin. Active network projects are those identified in system impact studies and whose construction awaits execution of an Interconnection Service Agreement. Under construction and In-service statuses have their plain meaning for both baseline and network transmission system enhancements.

Figure 4: Annually Approved Baseline and Network Projects Plus Supplementals[11] (2005 - 2018)

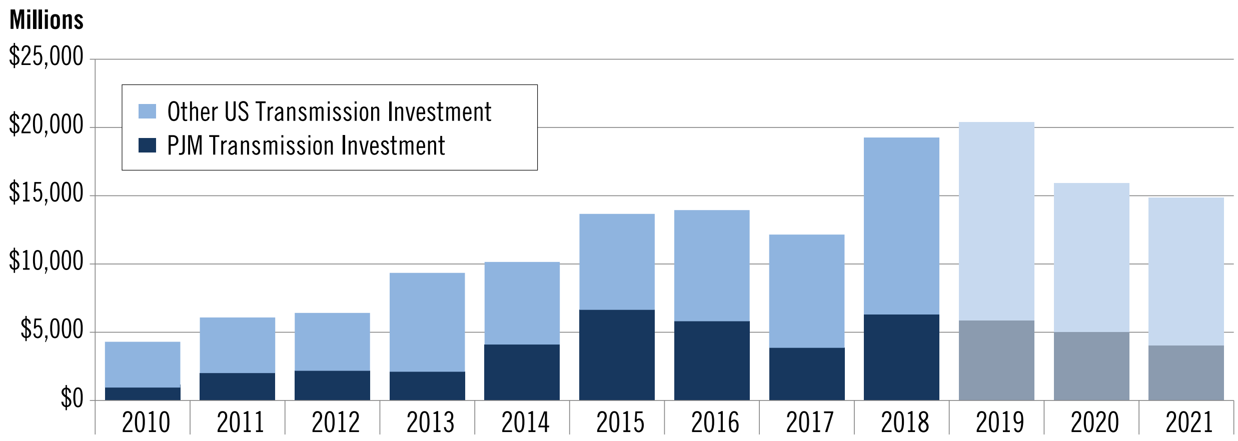


Transmission Investment Nationwide

Since 1999, the PJM Board of Managers has approved transmission system enhancements totaling $37.1 billion.

PJM is not alone in its need for new transmission assets. Other ISOs/RTOs and transmission owners have identified the need for new transmission as well. **Figure 5** provides a summary[12] of historical and projected investment in transmission infrastructure across the U.S. Historical and projected transmission investment in the U.S. has continued to grow since 2010 in ISO/RTO footprints and utilities that are not part of such entities. Available data indicates that, in light of its geographic scope, PJM may outspend other areas of the country in absolute dollar terms, but on a megawatt load-weighted basis, transmission investment in PJM is about average when compared to other ISO/RTOs as shown in **Figure 5**.

Figure 5: Historical and Projected U.S. Transmission Investment (estimate)

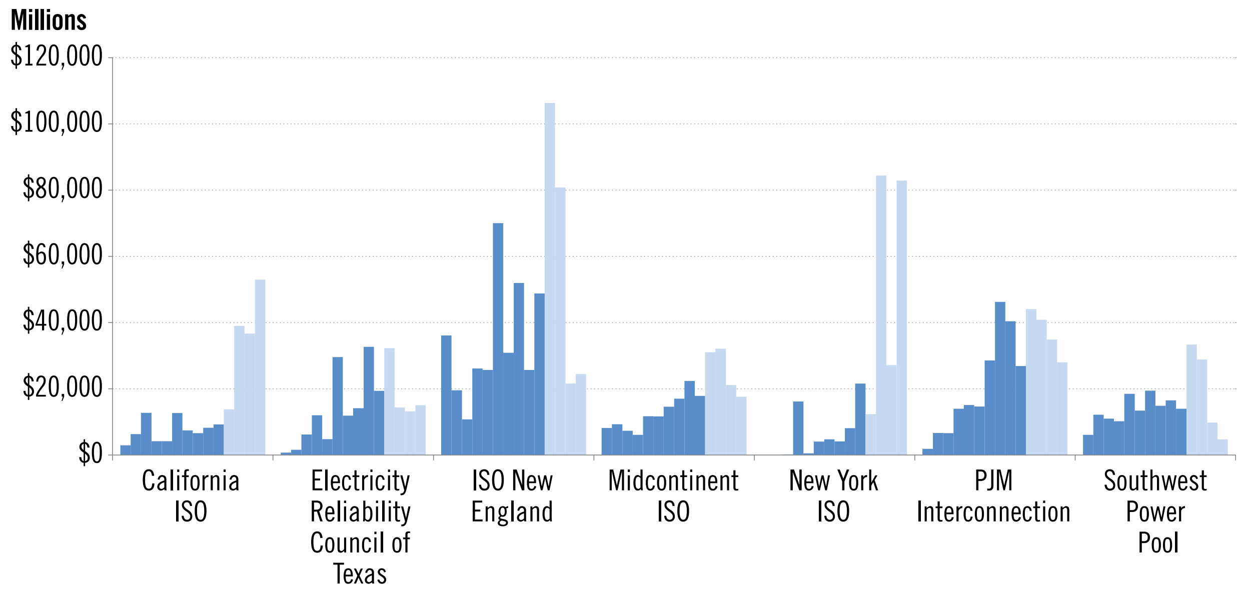


11 **Figure 4** and **Figure 5** include 2015 and 2016 investment numbers that include completion of the Susquehanna-Roseland, PSE&G's Northeast Grid Reliability and TrAIL projects. These accounted for $12.4 billion of the total across the country in those two years.

12 **Figure 5** is based on data provided by a third-party vendor that compiles from a variety of sources and includes data from RTO/ISOs as well as systems outside those footprints. Reporting differences suggest that the national totals are likely measurably higher. As such, the visual is for high-level comparison only.

Figure 6 presents a high-level comparison of RTO/ISO transmission investment from 2008 through 2021 as weighted by 2016 load to provide better perspective across systems of different sizes. Both figures suggest that, despite flattened load growth nationally, transmission investment has continued for a variety of reasons, including aging infrastructure, interconnection of generation powered by renewable fuels and other state policy mandates. PJM notes that both figures show investment numbers in 2015 and 2016 that include completion of the Susquehanna-Roseland, PSE&G's Northeast Grid Reliability and TrAIL projects. These accounted for $12.4 billion of the total $27 billion across the country in those two years.

Figure 6: Load-Weighted Transmission Investment Costs by RTO/ISO (2008 to 2021)



Supplemental Projects

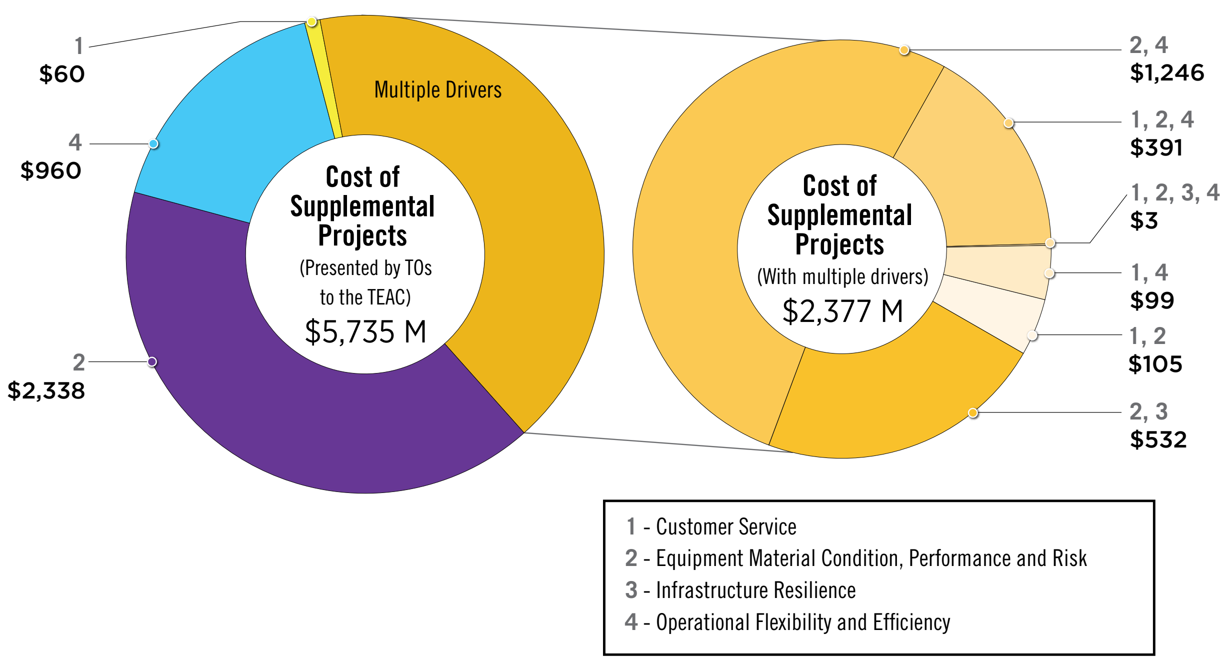
Supplemental projects, known at one time as transmission owner-initiated projects, are not a result of PJM RTEP process studies to ensure compliance with NERC and regional reliability criteria, operational performance, and market-efficiency economic criteria. However, TOs' supplemental projects ensure that issues on lower voltage and local transmission facilities are addressed. PJM reviews supplemental projects to ensure they do not introduce other reliability criteria violations. Supplemental projects are introduced to the PJM regional planning process through PJM's Transmission Expansion Advisory Committee (TEAC) and sub-regional RTEP committees. While not subject to PJM Board approval, they are included in PJM's RTEP models and evaluated to identify any reliability criteria violations requiring solutions.

Supplemental projects are foundational to TO management of their transmission assets and provide significant benefits to customers:

- Planning functions not transferred to PJM (e.g., asset management, load customer connections)
- Continued reliable operation of the local transmission systems, meeting customer needs, fostering economic development opportunities, enhancing grid resilience and security, ensuring public safety, and helping to promote renewable resource integration
- Obligation-to-serve grounded in good utility practice

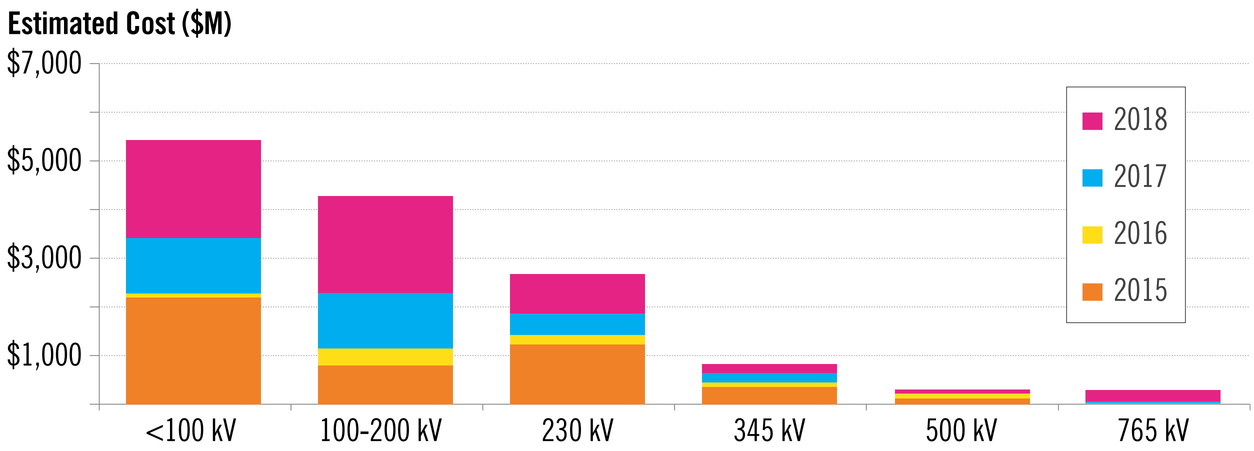
While supplemental projects have a range of drivers, they all improve the TOs' ability to provide reliable service to their customers and enhance system reliability. PJM remains committed to facilitating the process by which stakeholders are able to review the need for these projects to ensure transparency consistent with FERC requirements. In 2018 for example, PJM evaluated TO supplemental projects totaling approximately $6 billion (see **Figure 7**).

Figure 7: PJM Transmission Owner 2018 Supplemental Projects by Driver



As **Figure 7** shows, $2.4 billion of supplemental projects in 2018 had more than one driver. **Figure 8** shows a breakdown by year and voltage for supplemental projects reviewed by PJM from 2015 through 2018.

Figure 8: PJM Transmission Owner Supplemental Projects by Voltage (2015-2018)



A BRIEF HISTORY OF THE TRANSMISSION SYSTEM

Since the beginning of the electric industry, the purpose of transmission has been simple: move power efficiently from a generator to the customers that use it. The evolution of alternating current (AC) power technology in the late 19th century allowed for the development of large centralized power plants, enabling economies of scale that helped (and still help) drive down the cost of electricity for consumers while improving reliability.

In 1896, a 20-mile 11,000-volt (11 kV) AC line was built from a hydroelectric generator at Niagara Falls to power streetlights in Buffalo, N.Y. By 1930, transmission capability had increased up to 240,000 volts (240 kV). In the 1930s, electric service became more common in cities, where population density could support the costs of building generators and transmission lines. However, reaching rural communities was expensive. Fewer customers were located across wider expanses of land. As part of President Franklin Roosevelt's New Deal, high-voltage transmission was built into rural areas to reach the 90 percent of farmers who were without power. Doing so modernized farming and raised the standard of living in many rural communities.

Demand for electricity has continued to grow through the 20th century and beyond, and new, higher-voltage transmission technology has allowed increasingly higher volumes of power to be moved even more efficiently and economically from generation to customer.

A 220 kV Ring: The Landmark Interconnection that Became PJM

As the demand for electric service grew in the 1920s, the Philadelphia Electric Co., Pennsylvania Power & Light Co. and the Public Service Electric & Gas Co. signed an agreement that brought electricity from the Conowingo Dam on the Lower Susquehanna River in Maryland to Philadelphia's burgeoning western suburbs and helped enhance savings and reliability across the three territories. That agreement formed a "power pool," the beginning of PJM.

Savings, Efficiency, Reliability

A 1925 study predicted that by 1935 the creation of the 200-mile, 220 kV transmission ring interconnecting the three territories would result in an average annual savings of at least $3 million ($53 million in 2017 dollars) from "load diversity." Load diversity occurs when different areas experience their highest usage at different hours or even on different days. At those times, extra generation from a lower-demand area can be sent to a higher-demand area where it's needed. This ability to pool resources across service territories via transmission helped reduce costs as well as the need for additional power plants.

Transmission Delivers Distant Generation

Achieving these economies of scale remained a major focus throughout the 20th century. More utilities joined the PJM power pool to develop large generation stations in the coal-rich regions of western Pennsylvania. Having generators close to the source of their fuel cut costs even more. Units 1 and 2 at the Keystone plant in Shelocta, Armstrong County, Pa., began service in 1967 and 1968, respectively.

Units 1 and 2 at the Conemaugh generating station at New Florence, Indiana County, Pa., began in 1970 and 1971. Combined, these coal-fired units – built near the mines from which their fuel came – could produce 3,400 MW.

High-voltage transmission played a key role in the strategy behind these plants. Rather than building them near population centers in the eastern part of PJM, they were built close to the fuel source to spare the cost of shipping coal long distances. Bulk electricity was delivered economically to load centers via newly developed 500 kV extra-high-voltage transmission lines extending from the Keystone to Juniata 500 kV substation in central Pennsylvania, through the Peach Bottom and Whitpain 500 kV substations in southeastern Pennsylvania, and the Branchburg 500 kV substation in central New Jersey. This strategy would be employed throughout the rest of the 20th century and beyond, steadily continuing to save consumers money, increase efficiency and enhance reliability.

In western PJM, American Electric Power (AEP) installed the first 765 kV transmission line in 1969. Doing so enabled the highest utilization of its generating assets and provided much greater operational flexibility to address a wide range of potential contingencies and future uncertainties. AEP's completion of its 765 kV network in the early 1970s allowed it to meet significant load growth and provided it the flexibility to address unforeseen issues in siting and constructing new generation.

Transmission Enables Competition

Transmission lines enabled the evolution of centralized dispatch to deploy power resources in economic order, least-expensive resources first. While not an energy market as it is known today, transmission allowed the introduction of competition to supply consumers with the lowest-cost power.

The Path to Open Access and Competition

A variety of federal legislative and regulatory actions involving transmission were fundamental to opening up wholesale electricity markets to competition. The intention was to provide fair, open and reliable electric service at the lowest-possible cost to consumers.

1935 — **The Federal Power Act**
Authorizes the Federal Power Commission to regulate all interstate electricity transmission and wholesale power sales

1978 — **Public Utilities Regulatory Policies Act**
PURPA Requires utilities to buy power from on-utility generators and gave independent power producers access to the grid

1992 — **Energy Policy Act of 1992**
Requires that competitive generators and utilities be allowed access to the transmission system at rates and terms comparable to what a TO would charge itself

1996 — **FERC Order No. 888**
Details how TOs should provide open non-discriminatory access to the transmission system; requires that generation and transmission businesses be separated

FERC Order No. 889
Establishes an Internet-based system for TOs to post available capacity on their lines so companies looking to transport power can see availability

1999 — **FERC Order No. 2000**
Encourages transmission-owning utilities to join RTOs and sets minimum standards for those RTOs

2004 — **FERC Order No. 2003-A**
Requires TOs to interconnect all generators over 20 MW to the transmission system using a standard set of terms and conditions and a standard process

2005 — **Federal Energy Policy Act**
Recognizes need to develop transmission; allows FERC to authorize eminent domain proceedings to complete critical projects

2007 — **FERC Order No. 890**
Reforms orders 888 and 889 to ensure transparency and coordination in grid planning

2011 — **FERC Order No. 1000**
Requires transmission providers to participate in a regional planning process and seeks to introduce competition to transmission development

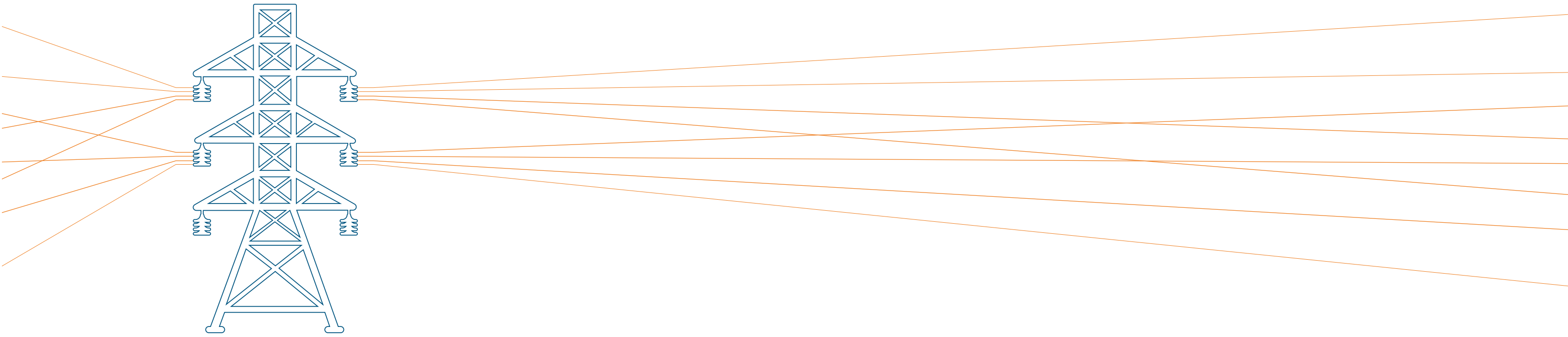
This would be brought into sharper focus in the 1970s. The 1973 OPEC oil embargo caused a sharp increase in U.S. energy prices, which rippled through the electric industry in the form of rate increases. Around the same time, ratepayers also started facing sharply higher prices, called rate shocks, from billion-dollar nuclear power projects. Seeking ways to increase domestic energy production, reduce dependence on foreign oil and keep rates down, Congress passed the Public Utilities Regulatory Policies Act (PURPA) in 1978. This required utilities to buy electricity from independent power producers, which meant these newly emerging generators needed access to the transmission system. PURPA triggered a series of steps introducing competition to the electric industry. The process eventually put transmission at the center of the evolution. No longer were transmission lines just a means for transporting bulk power. They ultimately became the vehicle that enabled competition in wholesale power markets.

The 1990s and Open Access

In the 1990s, Congress and FERC continued to pass additional legislation and regulations to enhance competition and give open access to the transmission system at reasonable rates. FERC also required utilities to separate their generation and transmission businesses to help create a fair and level playing field. FERC has subsequently ordered all RTOs to implement transparent and coordinated regional transmission system expansion planning. This is intended to ensure reliability, encourage development of new transmission and allow for open discussion of needs and solutions.

Continued Evolution

An agreement in 1927 established the power pool that has evolved into today's PJM Interconnection. The reliability and savings promise of the original interconnection has been fulfilled: Today, delivery of electric power over the high-voltage transmission system is more reliable than ever.



Section 2 The Capacity Benefit of Transmission

Ensuring an Adequate Supply of Power

The transmission links that tie PJM areas together ensure the region has enough resources to meet consumers' demand for electricity. Each individual locational deliverability area (LDA)[13] is able to rely on those links to meet consumers' needs more economically and efficiently than if each were to go it alone. The capacity resource requirements for PJM as a whole have decreased with the increase in load and generation diversity that has accompanied the integration of each additional service territory integrated into the PJM region. PJM's capacity auction provides a market for PJM to secure sufficient generating capacity to meet forecasted customer load three years forward. Historically, the capacity market has attracted sufficient capacity investment to meet future needs. Through 2022, PJM has procured 21 percent higher reserves than the forecasted peak electricity demand.

New Transmission's Impact on Individual LDAs

The ability to transmit power across transmission lines into each of the 27 LDAs in PJM – shown on **Map 2** and defined in **Appendix B** – has a direct bearing on reliability and capacity prices in PJM's capacity market auction. The maximum permissible level of this transfer capability (as determined by PJM based on NERC criteria), is called the capacity emergency transfer limit (CETL).

A CETL is the maximum amount of megawatts that an LDA can import before encountering a thermal or voltage reliability criteria violation,[14] as determined by PJM power flow studies. CETL values are affected by transmission system enhancements, load forecasts, generation additions and generation deactivations. New transmission assets increase the transfer capability into an LDA, which is a benefit to the capacity market.

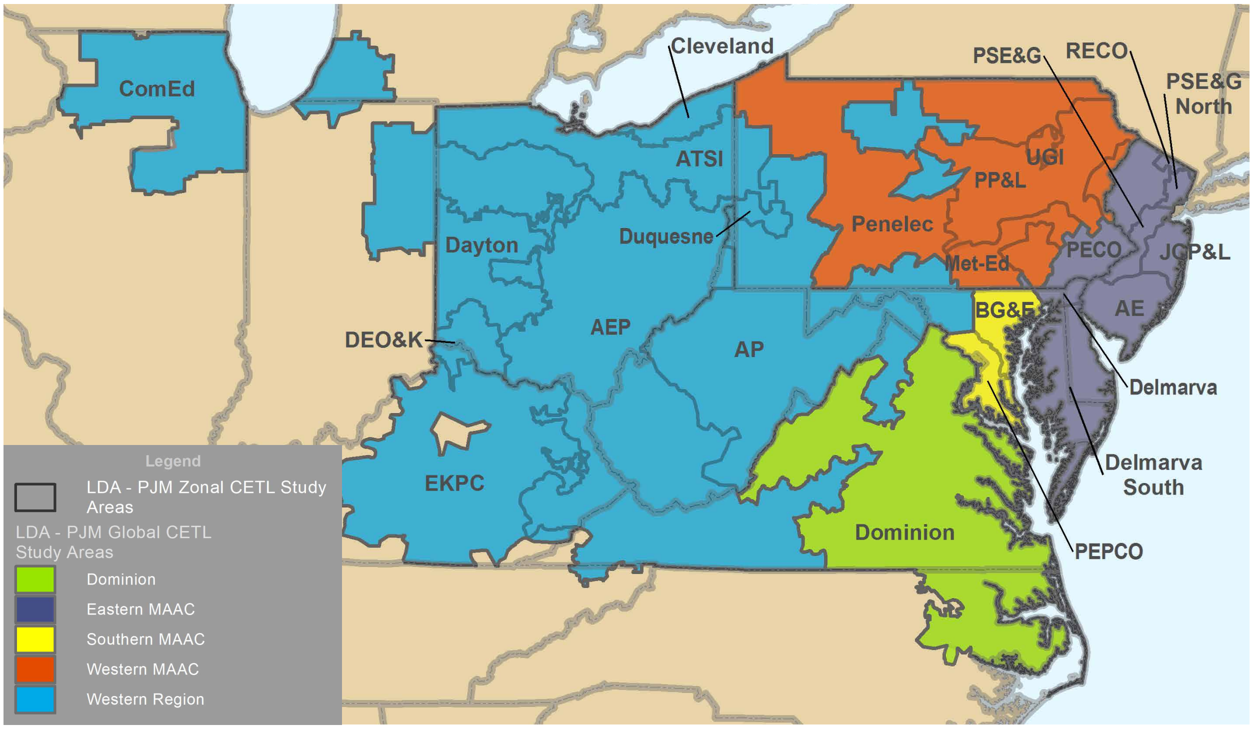
New Transmission Increases Import Capability

PJM's 2021/22 capacity market auction results offer perspective on how much new transmission assets increase import capability. In that auction, the import capability of a number of LDAs increased due to new transmission assets that reached commercial operation from 2013 to 2018. The need for these system enhancements was driven by thermal or voltage reliability criteria violations. One LDA saw increased import capability of 2,450 MW. While not all LDAs increased this much, these types of increased transfer limits are likely to result in a lower capacity auction clearing price for that LDA and, therefore, reduce capacity costs to consumers.

13 Locational deliverability areas are electrically cohesive load areas historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas, as defined in **Appendix B**.

14 Under defined peak-load test conditions.

Map 2: PJM Locational Deliverability Areas



> Increased transfer capability can lower capacity auction clearing prices.

An LDA's CETL value must exceed its capacity emergency transfer objective (CETO). The CETO is the transfer capability required to ensure that available generation will be able to meet customer demand and avoid a customer load interruption event at a risk of no more than once in 25 years. Enough transmission assets ensure that the LDA can continue to serve load. If the CETL value is less than CETO – as determined by power flow analyses – the reliability test fails, which indicates that additional transmission capability is needed. Increasing an LDA's import capability lowers the likelihood of price separation in a capacity auction, driving lower capacity procurement costs to customers in an LDA.

PJM's capacity auction provides a market for PJM to secure sufficient generating capacity to meet forecasted customer load three years forward. Historically, the capacity market has attracted sufficient capacity investment to meet future needs. Through 2022, PJM has procured 21 percent higher reserves than the forecasted peak electricity demand.

Sharing Capacity Resources

Three factors that arise from market integrations provide capacity benefits to load in PJM: increased load diversity, a wider portfolio of generating resources, and transmission ties to neighboring systems. PJM's market integrations have enhanced the value of the transmission assets that link the TO zones. Since 2002, PJM has added seven transmission zones to the PJM footprint. These integrations have enabled the addition of 112,000 MW of generation and 95,000 MW of peak customer demand. The vastly increased generating capacity and electric demand that have resulted from the integrations allows the most-efficient generation dispatch from a much larger fleet of generators. This has also increased competition, which lowers costs to consumers.

Load Diversity

Transmission has enabled seven TO systems to integrate into the PJM region since 2002, increasing reliability and capturing ever larger economies of scale. Load diversity[15] alone across PJM has increased from 1 percent to 3.5 percent since PJM's first market integration in 2002. For perspective, the current load diversity across PJM's original footprint is 1,213 MW whereas as the load diversity across the current PJM footprint is 5,980 MW. This 4,767 MW increase enhances reliability as it allows zones with excess capacity at the time of PJM's peak customer demand to export capacity to zones in need. This reliability benefit is enabled by the 325 inter-zonal transmission lines connecting each TO zone to adjoining zones.

More Generating Resources

Considered holistically, load diversity, together with a generation fleet composed of units with diverse sizes and outage rates has reduced the capacity reserve levels needed to supply customers. For example, the generation reserve requirement for the original Mid-Atlantic area of PJM before any market integrations was approximately 22 percent. Today it is 15.7 percent.

Transmission assets also provide access to capacity and energy in adjoining power markets. Because of its external ties, PJM can carry about 2,500 fewer megawatts of installed reserves, which, in turn, can help reduce costs to consumers.

> Transmission links PJM zones together, allowing them to share capacity, and reducing the need for new generation by $3.78 billion annually.

Meeting Resource Requirements

Resource adequacy is measured in terms of installed reserve margin (IRM). IRM is the level of capacity reserves – typically expressed as a percentage in excess of annual peak demand – needed to satisfy PJM reliability criteria. The criteria state that the available generation resources will be able to meet the demand for electricity and avoid customer load interruption events with a risk of no more than once in 10 years. PJM's capacity market provides the forward-looking market vehicle by which sufficient generation is procured to meet IRM.

Transmission links between LDAs mean that lower levels of capacity are needed to serve the whole system reliably. Recent analysis (see Benefits by the Numbers below) has shown that up to 33,000 fewer megawatts are needed across PJM because of the transmission ties among LDAs. Those facilities have an economic value in PJM as high as an estimated $3.8 billion. Considering the additional operational efficiencies that are gained through internal transmission ties among PJM zones, the overall value is potentially even higher.

Benefits by the Numbers: Capacity Market Results Without Internal LDA Ties or External Ties

The capacity market is key to future reliability. PJM's annual capacity market auctions, which look three years forward, have continued to attract sufficient generation investment to meet consumers' future electricity needs. Through 2022, PJM has been able to procure 21 percent higher reserves than forecasted peak electricity demand, more than the minimum RTO requirement. To quantify the impact of existing transmission on capacity market outcomes, PJM conducted a scenario study in which all transmission lines linking PJM zones to each other and to adjacent systems were "removed." Once isolated from each other, each zone required significantly more generation investment internally to meet reliability requirements.

15 Load diversity is defined as the sum of all zonal non-coincident MW annual peaks minus the RTO coincident MW annual peak.

PJM first computed a “stand-alone” IRM for each individual zone with the assumption that each had no transmission ties to the others or to systems adjoining PJM. Doing so revealed that these “stand-alone” zonal IRMs were generally in the 20 percent to 50 percent range, with smaller zones tending to have higher IRMs. Each stand-alone zonal IRM was converted to a megawatt requirement by multiplying it by the zone’s forecasted 2020 summer peak load. Those calculations revealed that five zones were still able to satisfy their stand-alone zonal megawatt requirement. Existing supply capability in each of the remaining 14 zones, however, fell short of meeting respective stand-alone zonal megawatt requirements. As **Table 1** shows, meeting IRM requirements for those 14 zones amounted to an additional 33,000 MW[16] to satisfy the one in 10 loss of load expectation requirement for each. This translates into an annual avoided capacity investment – or savings – of $3.78 billion, assuming a typical new generator start-up cost of $313.62 per megawatt-day as identified for the 2021/22 capacity market base residual auction.

Table 1: Stand-Alone Zonal MW Requirement Analysis – Zones Unable to Meet MW Requirement

Aggregate Zone Data	Zonal MW Requirement
Aggregate “Stand-Alone” Requirement (MW)	150,385
Existing Generation (MW)	116,735
Existing Demand Response Resource (MW)	619
Aggregate Resources (MW) (Generation + Demand Response)	117,354
Additional Capacity Required to Meet Aggregate Stand-Alone Requirement (MW)	33,032

Interregional Tie Lines Provide Capacity Benefits

Transmission assets connecting PJM with neighboring systems support internal reliability and allow external generators to participate in PJM’s capacity market, which increases competition by reducing the cost of wholesale power and benefits end-use customers. In other words, external tie lines provide a quantifiable capacity benefit.

Benefits by the Numbers: Recent Base Residual Auction without External Ties

This analysis focused only on the capacity-related benefits of PJM’s tie lines to adjoining systems. PJM is examined as a single electrical region with inter-zonal transmission capability but with no interconnection to neighboring systems. PJM looked at the two most recent capacity market auctions and compared those auction results with external ties modeled with results from auction simulations without external ties modeled. The analysis revealed that without external ties:

> Transmission links to neighboring regions saved an estimated $1.7 billion (15 percent) and $1.3 billion (19 percent) in recent annual capacity auctions.

1. PJM would be unable to call on external resources in a capacity emergency, which is most likely to occur under peak load conditions. This would require an increase in the IRM and, consequently, the amount of generation resources needed to be procured to satisfy resource adequacy reliability criteria.

16 150,385 MW represents the aggregated megawatt amount required for the 14 stand-alone zones to meet their respective zonal IRMs. The aggregate amount of capacity supply resources available to those 14 zones totaled 117,354 MW: 116,735 MW of existing generation and 619 MW of existing demand response.

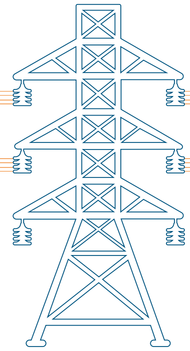
2. External generators would be unable to offer into the PJM capacity market, limiting the number of market players and reducing market liquidity and competition.

Without external tie lines, simulated auction results yielded an increase in total payments to capacity resources of $1.7 billion in the 2020/2021 auction and $1.3 billion in the 2021/2022 auction. This translates to 15 percent and 19 percent savings, respectively (see **Table 2**).

Table 2: Results of Base Residual Auction Scenario Testing[17]

	Base Residual Auction	
	2020-2021	2021-2022
Simulated Payments (Assuming no ties)	$11 billion	$8.3 billion
Existing Payments (With ties)	$9.3 billion	$7.0 billion
Difference in Payments	$1.7 billion savings	$1.3 billion savings
Difference (%)	**15% in savings**	**19% in savings**

17 Note that only these base residual auctions were examined, as prior to Delivery Year 2020/2021, resources offering into the base residual auctions were not subject to capacity performance requirements.



Section 3 Enabling a Reliable Generation Shift

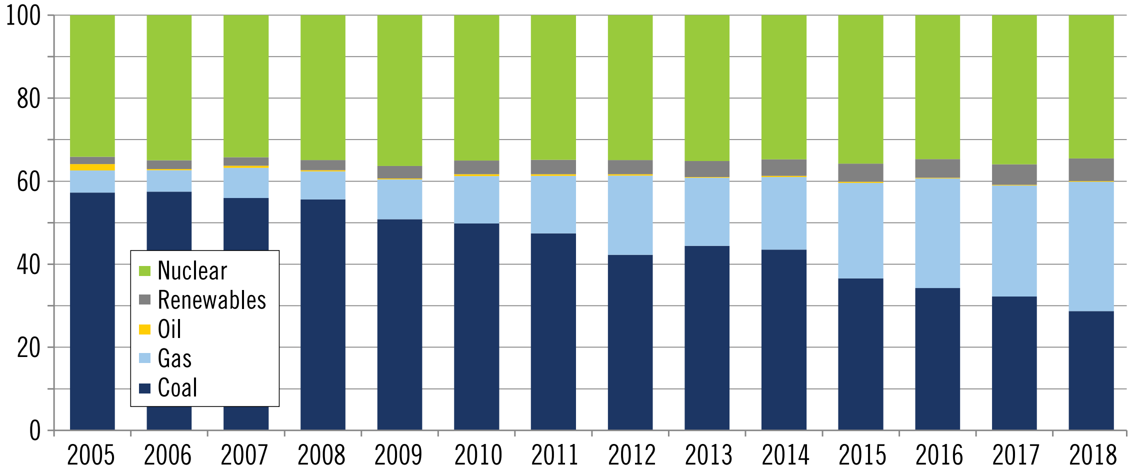
Transmission Supports Unprecedented Generation Shift

Across PJM, as in other areas of the country, the traditional fuel mix of the generation fleet continues to change. Driven by public policy, including renewable portfolio standards and environmental regulations, and the abundant shale gas in the PJM footprint, coal-fired generation is retiring and being replaced largely by natural gas-fired generation and renewable generation (**Figure 9**).

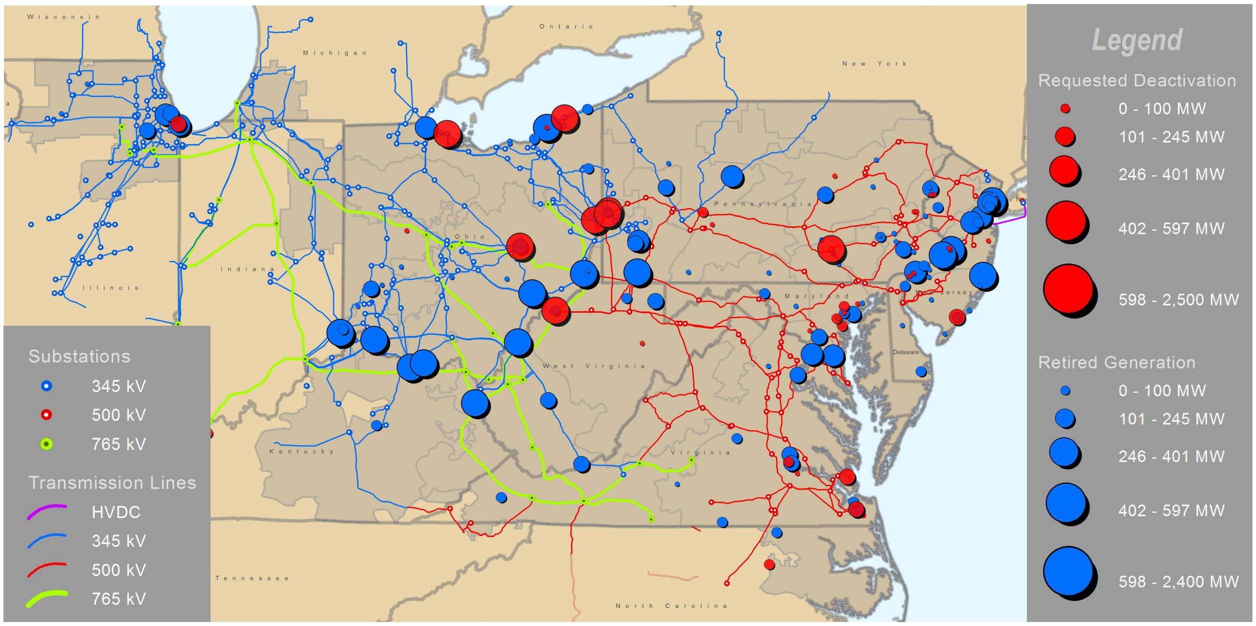
From 2011 through 2018, 258 generating units totaling 31,722 MW – from all fuel types – retired from service, shown in **Map 3.** More than 24,000 MW were represented by 125 coal-fired units, many more than 45 years old. For additional perspective, in 2018, PJM received 63 deactivation notifications totaling 12,279 MW for requested deactivations between April 2018 and June 2022, as shown in **Map 4.**

From 2011 through 2018, 31,722 MW of generation has retired, including more than 24,000 MW powered by coal-fired generation, some more than 45 years old. Retiring units have been replaced by more than 38,514 MW of new resources through December 31, 2018, including more than 29,500 MW of additional natural gas-fired generation and 5,910 MW of renewable wind and solar generation. New transmission assets continue to ensure reliability throughout this ongoing transition and beyond.

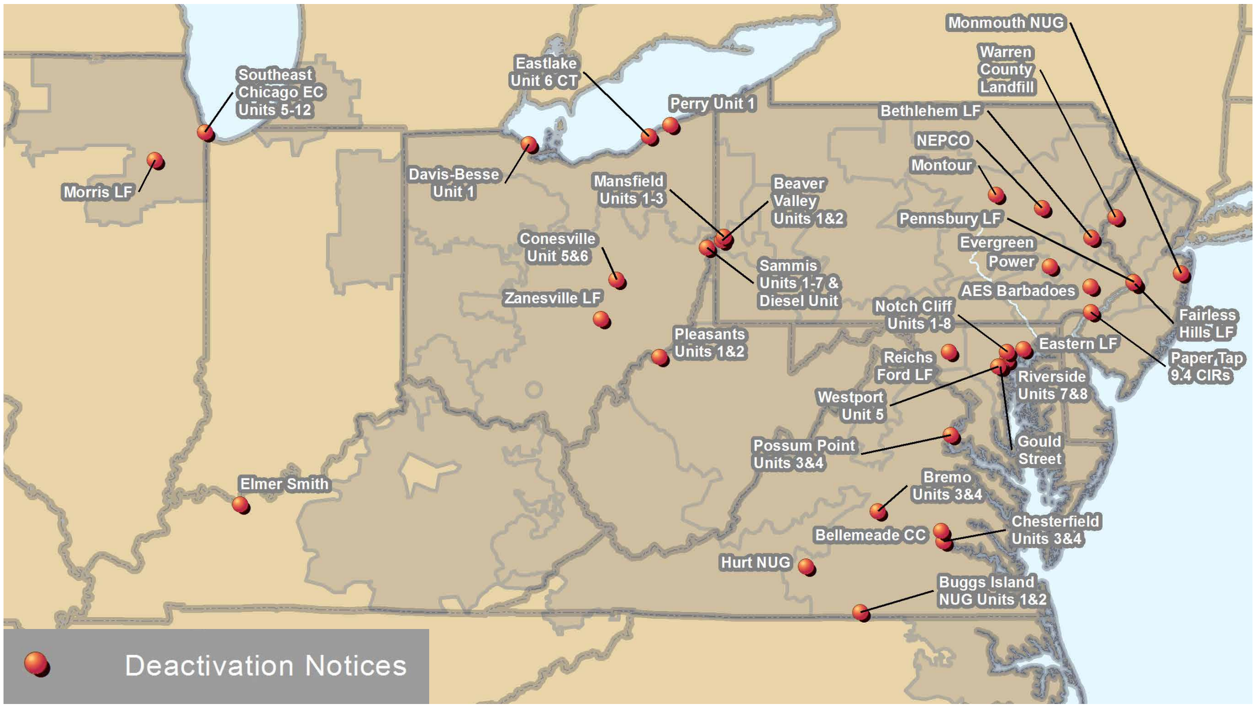
Figure 9: PJM Annual Fuel Mix



Map 3: All Generator Retirements Since 2010



Map 4: PJM Generator Deactivation Notifications Received January 1, 2018 through December 31, 2018



By contrast, PJM received and studied deactivation requests for only 11,000 MW in total during the eight years ending November 1, 2011. Retiring units have been replaced by more than 38,514 MW of new resources through December 31, 2018. Another 16,172 MW are under construction and 87,680 MW are actively under study in PJM's interconnection process. These units are primarily powered by natural gas and renewables like solar, wind and battery storage. A comparison of **Figure 10** and **Figure 11** provides additional detail. In particular, between 2011 and 2018, transmission system enhancements in PJM have enabled the interconnection of more than 29,500 MW of additional natural gas-fired generation and 5,910 MW of renewable wind and solar generation.

Even in the face of this unprecedented shift in fuel mix, the reliability of the system has never wavered. This is in large part due to the flexibility of the transmission system and a planning process that continually looks for and solves violations of established reliability criteria. New transmission has ensured reliable interconnection and delivery of the new resources while keeping the system reliable as units retire.

Figure 10: PJM Installed Capacity (December 31, 2005)

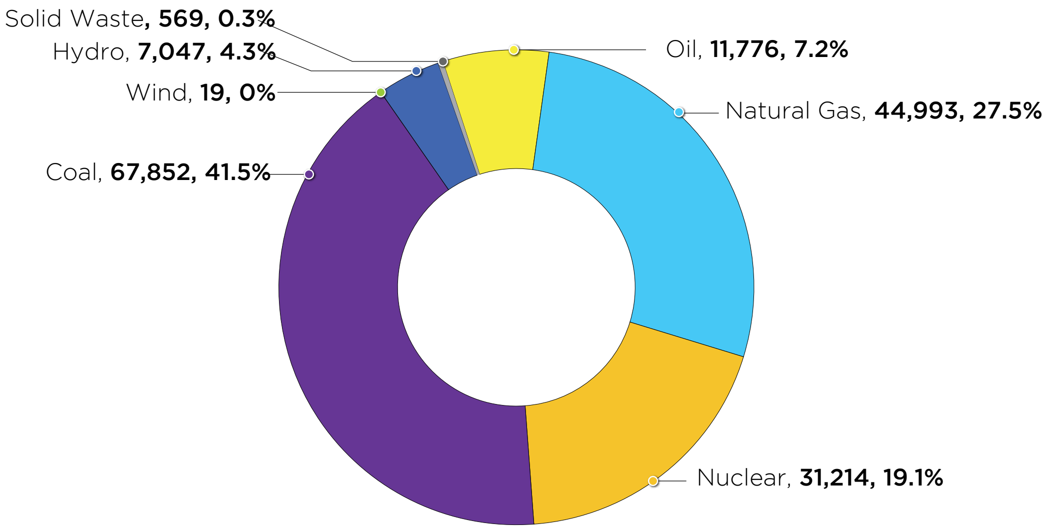
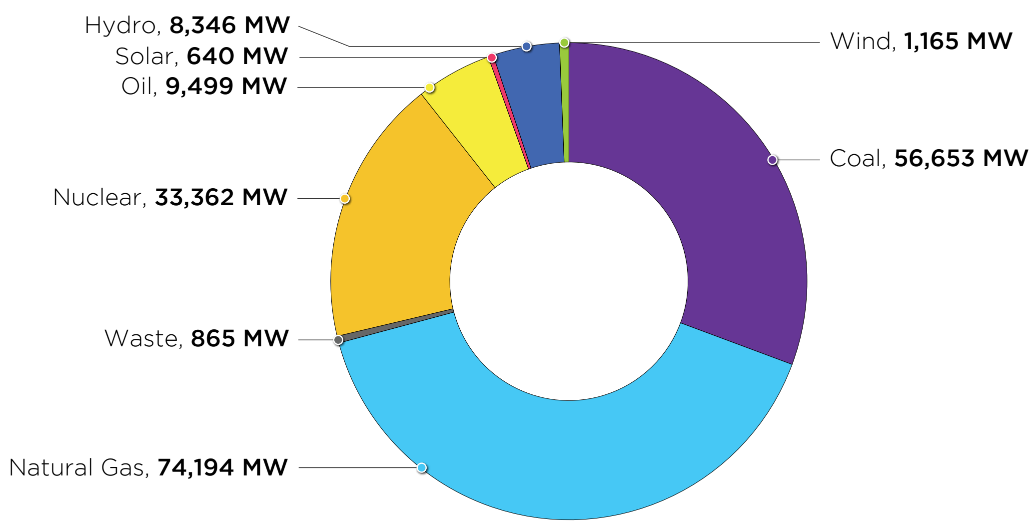


Figure 11: PJM Existing Installed Capacity Mix (December 31, 2018)



Generator Retirements

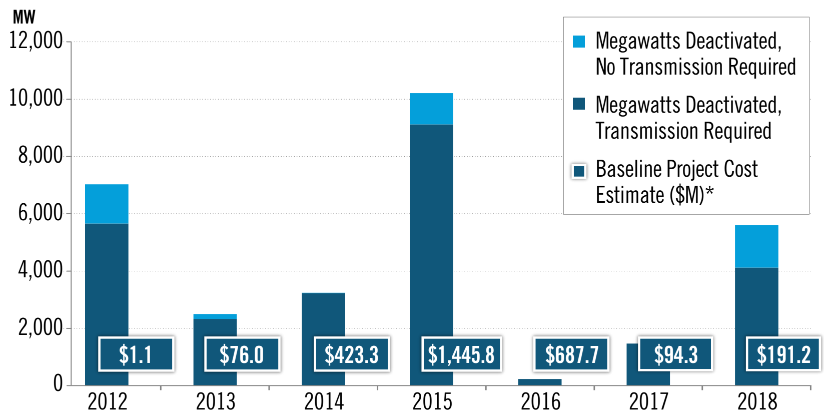
Transmission expansion continues as grid and consumer needs change. In the PJM region, older generators, particularly coal units, are retiring due to competition from newer technology and low natural gas prices. Such factors are driving the business decisions by generation owners to retire units, over 24,000 MW between 2011 and 2018. Generation owners are required to notify PJM of their intent to deactivate generation.[18] PJM cannot compel unit owners to continue to operate their units.

Unlike time lines associated with requests for interconnection, deactivation may take effect upon 90 days' notice. When PJM has received notice, it has 30 days to complete a reliability study and respond to the generation owner. This mandated time frame and the nature of the baseline system reinforcements required do not allow PJM to conduct an RTEP project proposal window to pursue solutions.

Benefits by the Numbers: Transmission Investment to Ensure Reliable Deactivations

Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage control. When PJM receives a formal generator deactivation request, PJM conducts thermal and reactive studies to ensure that remaining generation continues to be deliverable to load. If criteria violations are identified, PJM develops a solution in coordination with affected transmission owners.

Figure 12: PJM Transmission Investment Driven by Generator Deactivations



*Note: Cost estimate for baseline transmission enhancements required to allow generators to deactivate reliably

Figure 12 shows the transmission enhancements needed since 2012 to allow generators to deactivate reliably.

Interconnecting New Generation

Enabling a Diverse Fuel Mix

Transmission enables the development of all forms and sizes of generation, connecting it with consumers across the PJM region. PJM power markets have attracted over 544,000 MW of new interconnection requests since 1999 – shown in **Table 3** – equal to approximately 2.5 times PJM's current installed capacity. Overall, about 15 percent of requested capacity megawatts reach commercial operation. Queue activity reflects ongoing business decisions by developers in response to changing public policy, regulatory, industry, economic and other competitive factors.

Table 3: PJM Generation Interconnection Queue Status Totals (December 31, 2018)

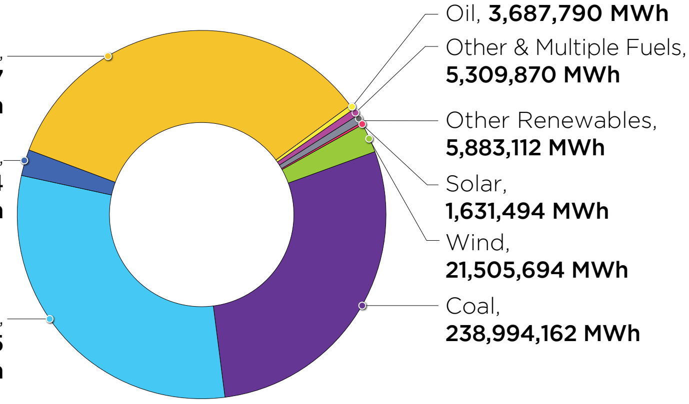
Status	Number of Projects	Requested Capacity Interconnection Rights (MW)	Nameplate Capacity (MW)
Active	663	53,762	85,430.5
In Service	816	51,943	61,128.0
Under Construction	201	17,797	23,433.9
Suspended	72	4,387	6,089.3
Withdrawn	2,508	296,739	368,341.9
Total	4,260	424,627	544,423.5

18 Per Article V of the PJM Open Access Transmission Tariff.

Existing Fuel Mix

A diverse generation portfolio reduces system risk associated with fuel availability and reduces market-price volatility. PJM's 184,724 MW of capacity market-eligible existing installed capacity reflects a fuel mix of about 40 percent natural gas, 31 percent coal and 18 percent nuclear. Hydro, wind, solar, oil and waste fuels constitute the remaining 11 percent. Capacity market-eligible natural gas-fired generation capacity now exceeds that of coal. This diversity is reflected in annual energy production as well, as shown in **Figure 13** for 2018.

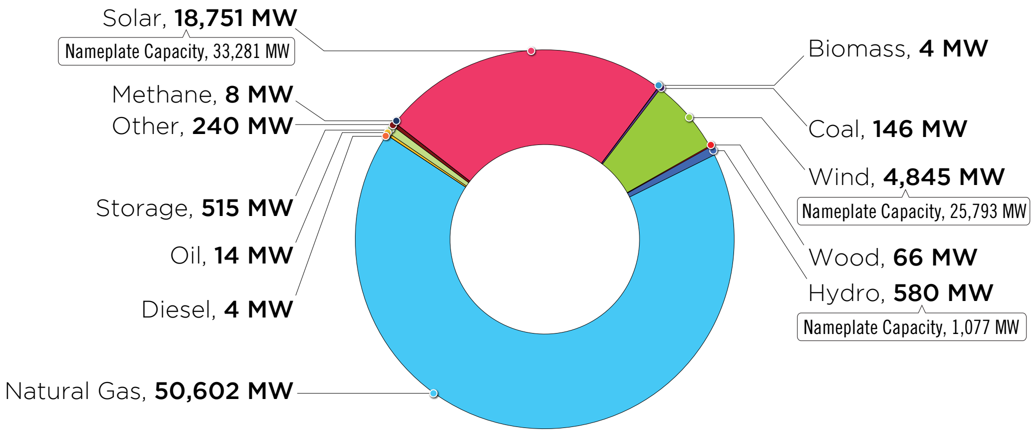
Figure 13: 2018 Energy Production by Fuel Type



Looking Forward

Currently, over 50,000 MW of new capacity powered by natural gas is seeking transmission interconnection to participate in PJM capacity and energy markets, much of it from the Marcellus and Utica shale deposits located in the middle of PJM's geographic region. This is in addition to the more than 74,000 MW already in service. This capacity exceeds that powered by coal, marking an unprecedented shift in PJM's fuel mix. Natural gas powers approximately 30 percent of the generation in PJM's interconnection queue (see **Figure 14**). The figure shows PJM's fuel mix based on requested interconnection capacity rights for generation active, under construction or suspended as of December 31, 2018.

Figure 14: PJM Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (December 31, 2018)

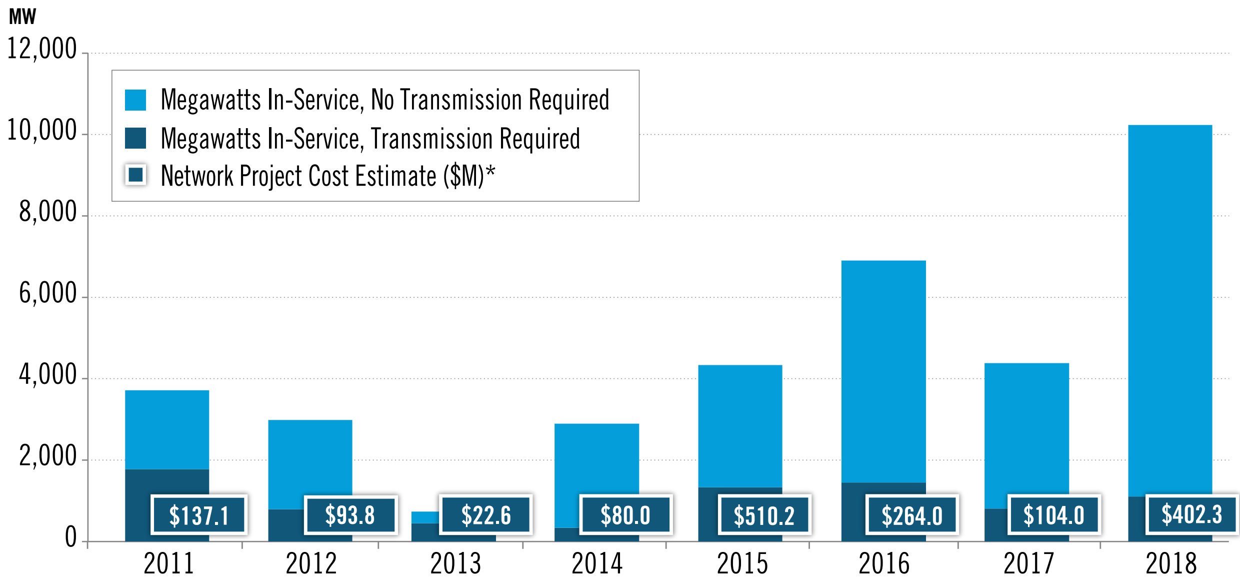


20 percent of all PJM-approved transmission investment since 1999 will enable the interconnection of new generation.

Benefits by the Numbers: Network Upgrades Enable New Generation

As summarized earlier, roughly 20 percent of all PJM-approved transmission projects since 1999 will enable over 85,000 MW of new generation, across all fuel types, to interconnect to the grid reliably. When PJM receives a completed interconnection request, PJM conducts a series of thermal, voltage, short circuit and stability studies to ensure compliance with NERC reliability criteria. If violations are identified, PJM develops a network solution in coordination with affected transmission owners. **Figure 15** shows the network transmission enhancements needed since 2011 to allow all new generators across all fuel types to interconnect reliably. Once those transmission facilities are in place, generators can participate in PJM capacity, energy and ancillary services markets.

Figure 15: Network Transmission Enhancements for New Generation – All Fuel Types



*Note: Cost estimate for network transmission enhancements to allow generation – all fuels – to interconnect reliably

Access to Shale Gas-Fired Generation

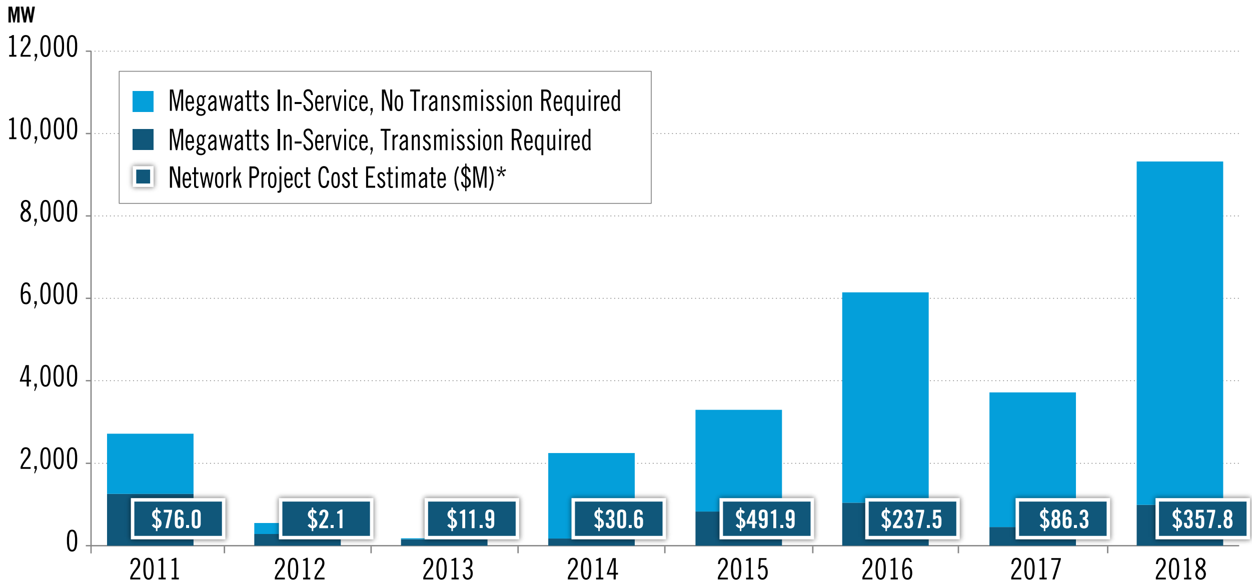
New transmission provides generation powered by the abundant Marcellus shale and Utica shale natural gas found in the PJM footprint access to a broad range of markets via the PJM transmission system. The regional transmission grid provides a market outlet for this generation.

> Robust transmission has enabled a generation shift from coal to natural-gas-fired generation, saving consumers money and helping to reduce emissions.

Benefits by the Numbers: Transmission Enables Shale Gas-Fired Generation

Since 2011, more than 29,500 MW of natural gas-fired generation has been able to interconnect reliably to the PJM transmission grid to reach consumers across the footprint. As with proposed generation of other fuel types, when an interconnection for such generation is received, PJM conducts a body of studies to identify the existence of reliability criteria violations. If violations exist, PJM develops a network solution in coordination with affected transmission owners. **Figure 16** shows the network transmission enhancements needed since 2011 to allow generators powered by natural gas to interconnect reliably.

Figure 16: Network Transmission Enhancements for New Generation – Natural Gas



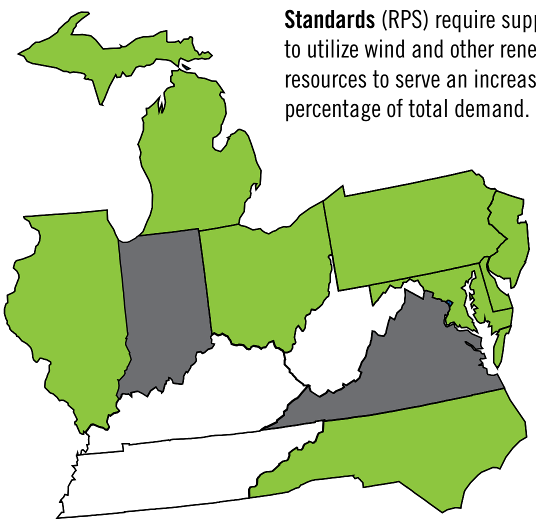
*Note: Cost estimate for network transmission enhancements to allow natural gas-fired generators to interconnect reliably

Transmission Enables Renewables

Transmission enables customer access to renewable power, much of it driven by states' renewable portfolio standard mandates, as shown in **Figure 17.** There has been significant growth in wind- and solar-powered generating plants in PJM. **Figure 18** depicts the growth in wind capacity since 2005; in particular, it shows proposed onshore and offshore wind capacity in comparison to the cumulative amount needed to meet requirements proposed by the states in which PJM operates. Transmission provides the means with which to deliver this renewable energy. **Map 5** shows the wind- and solar-powered generators currently in service on the PJM system.

> Transmission enhancements will enable the interconnection of renewable energy resources such as utility-scale wind and solar plants.

Figure 17: State Renewable Portfolio Standard Targets



State Renewable Portfolio Standards (RPS) require suppliers to utilize wind and other renewable resources to serve an increasing percentage of total demand.

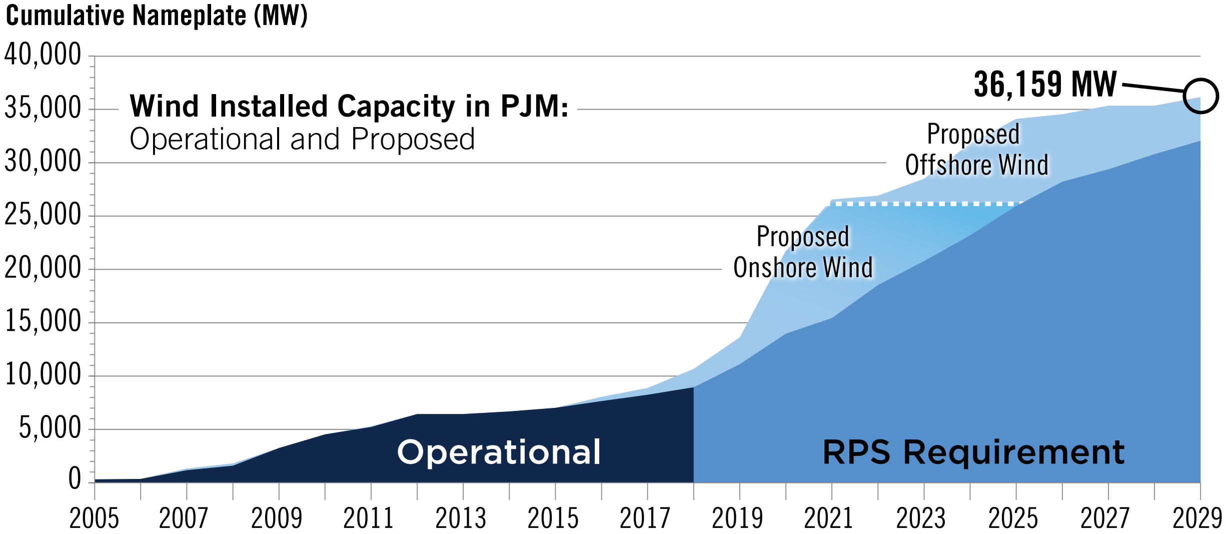
State RPS
State Goal
☼ Minimum solar requirement
** Includes non-renewable "alternative" energy resources

State RPS Targets

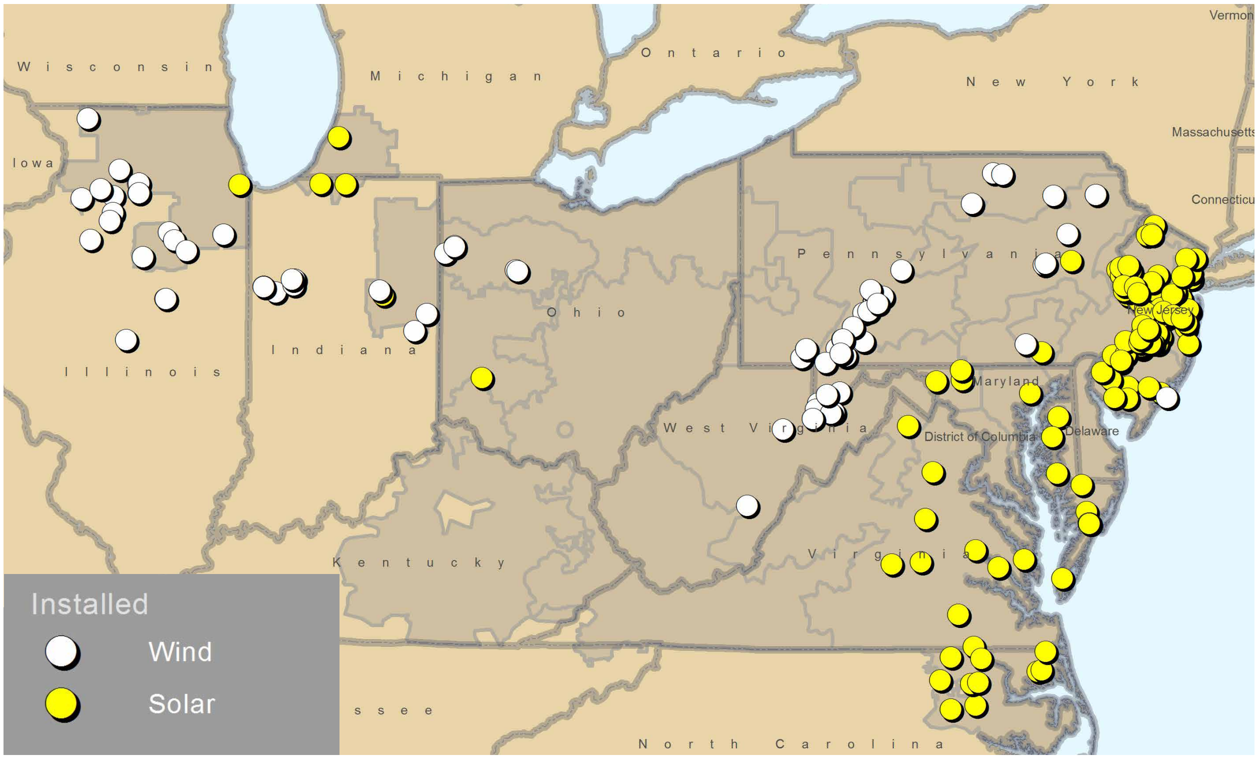
- ☼ NJ: 50% by 2030
- ☼ MD: 25% by 2020
- ☼ DE: 25% by 2026
- ☼ DC: 100% by 2032
- ☼ PA: 18%** by 2021
- ☼ IL: 25% by 2026
- ☼ OH: 12.5% by 2026
- ☼ NC: 12.5% by 2021 (IOUs)
- MI: 15% by 2021
- VA: 15% by 2025
- IN: 10%** by 2025

Source: DSIRE, www.dsireusa.org, January 2019

Figure 18: Wind Capacity in PJM Since 2005



Map 5: Installed Wind- and Solar-Powered Generation in PJM (December 31, 2018)



Benefits by the Numbers: Transmission Enables Renewables

Generators are most economic when they are built at or close to the source of their fuel, such as coal mines, natural gas wells and hydroelectric dams. Wind and solar farms are no exception. They need to be located where the wind blows most or the sun shines most and they need transmission lines to carry their electricity to where it is used.

Between 2011 and 2018, 5,910 MW of wind and solar energy have been able to interconnect reliably to the PJM transmission grid to reach consumers across the region. **Figure 19** and **Figure 20** show the breakdown of existing and queued renewable generation, respectively. Corporate and voluntary purchases of renewable energy are becoming an increasingly significant driver for renewable energy development, facilitated by PJM markets. PJM also estimates that roughly 4,500 MW of distributed solar generation (such as rooftop solar panels) is present on the grid behind the meter.

Figure 19: Existing Installed Capacity – Renewable Fuels (December 31, 2018)

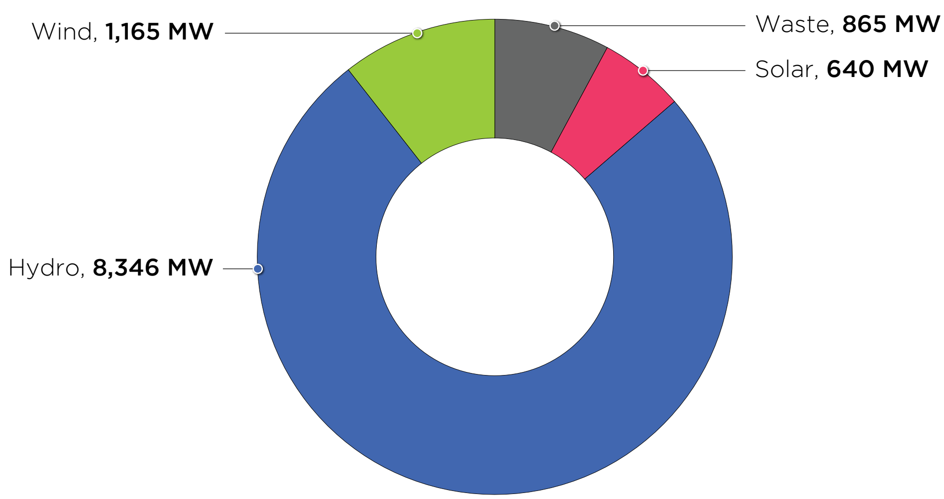
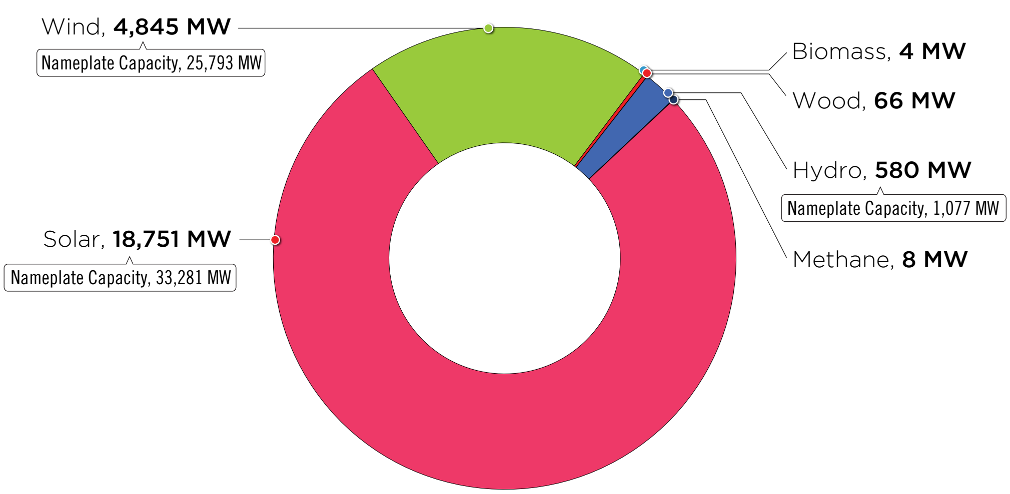
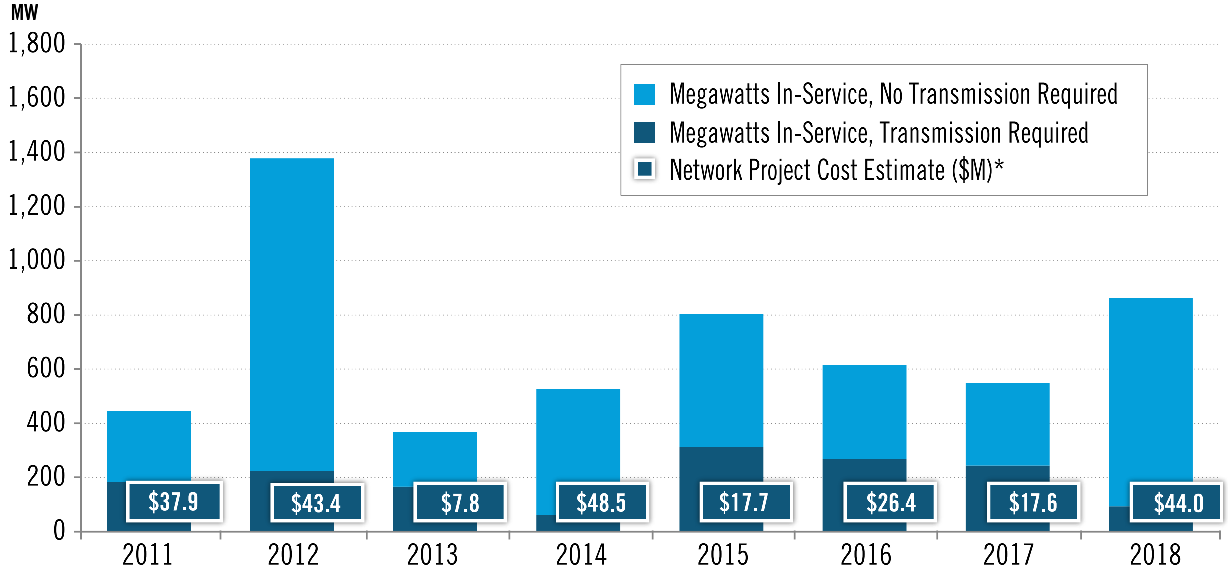


Figure 20: Queued Generation – Renewable Fuels (December 31, 2018)



PJM identifies reliability criteria violations and develops network solutions in coordination with affected transmission owners. **Figure 21** shows the network transmission enhancements needed since 2011 to allow generators powered by renewable fuels to interconnect reliably.

Figure 21: Network Transmission Enhancements for New Generation – Renewable Fuels



*Note: Cost estimate for network transmission enhancements to allow renewable-powered generation to interconnect reliably

Facilitating Emissions Reductions

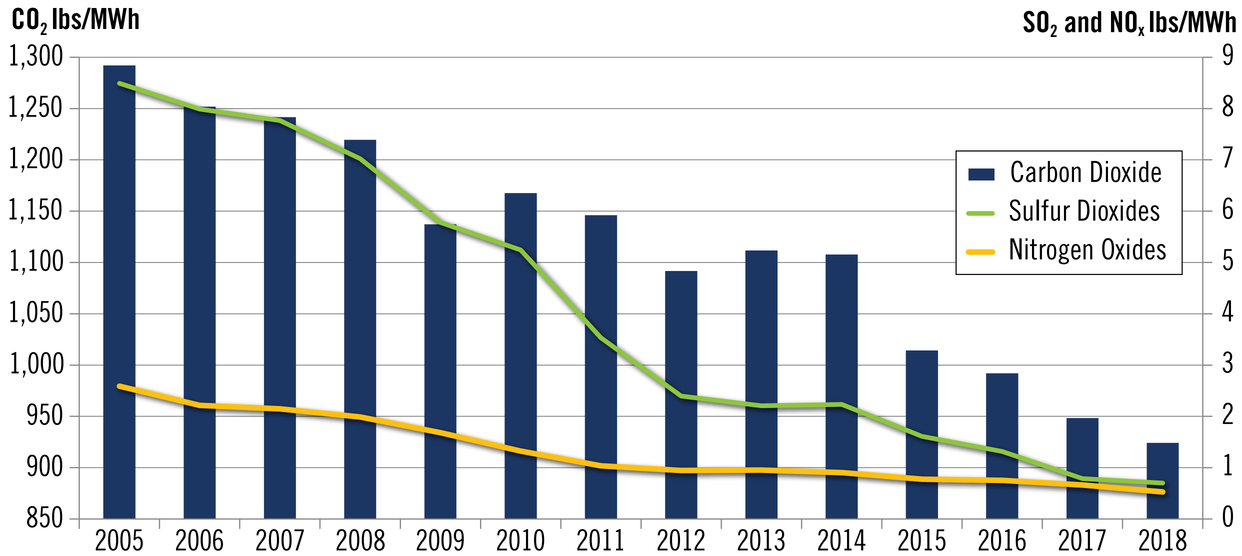
New technologies have improved efficiency with respect to emissions. Emission reductions are largely the result of competitive markets encouraging the entry of new, cleaner, competing technologies. Access to these resources would not be possible without the capability of the transmission system to deliver lower-emissions energy or renewable power.

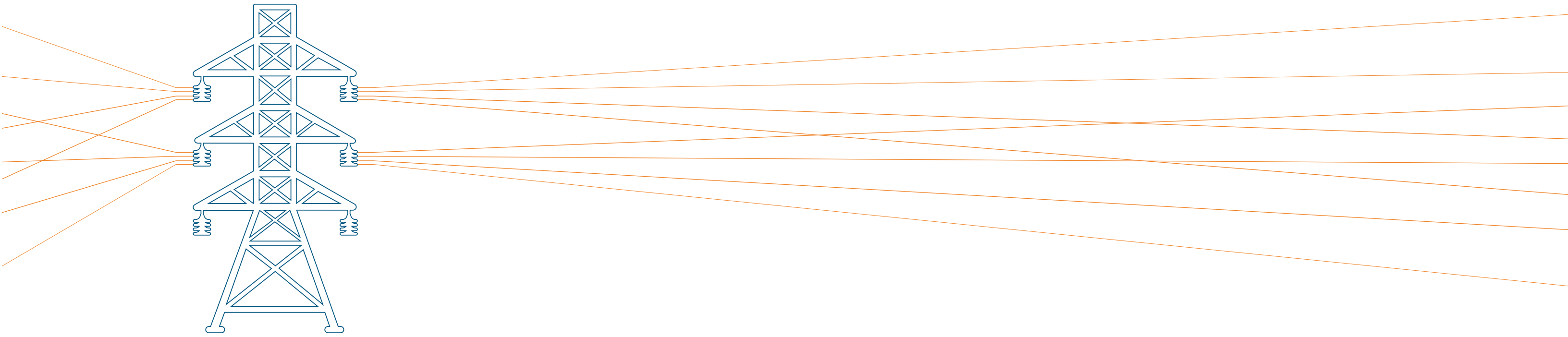
Benefits by the Numbers: Emission Reduction

Today, PJM's generation mix is 30 percent less carbon-intensive than 10 years ago. On average, producing one megawatt of power in PJM emits 13 percent less carbon dioxide than 10 years ago and 28 percent less than in 2005. This reduction has come at zero additional cost to consumers. **Figure 22** shows the reduction in carbon dioxide, sulfur dioxide and nitrogen oxide since 2005.

Transmission improvements have enabled a 30 percent reduction in carbon emissions over 10 years.

Figure 22: PJM Generation Portfolio Emission Reductions Since 2005





Section 4 Day-to-Day Operations – the Reliability Benefits of Transmission

A primary function of regional transmission organizations like PJM is to ensure that the supply and demand for electricity is reliable and perpetually in balance. PJM operators coordinate the flow of power across the transmission lines that link individual utilities and neighboring grid operators. The transmission assets in place today provide operators with the flexibility to manage the flow of power effectively and efficiently and to reduce the need for emergency procedures up to and including load shed. As discussed throughout this section, a robust transmission system gives grid operators valuable margin, or room to maneuver. This margin allows operators to address unexpected system events like loss of generation or loss of another transmission asset, such as a transmission line, a transformer or a substation.

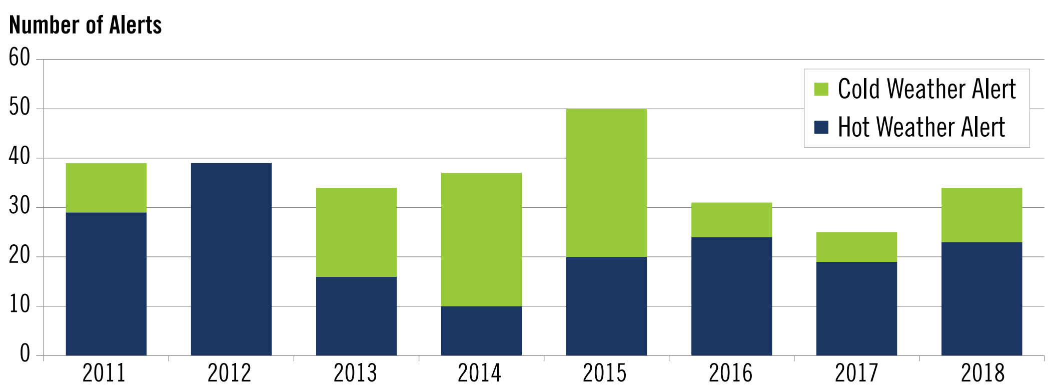
Power Delivery in Extreme Weather

Under emergency conditions in areas of PJM where generating capacity is limited, transmission lines ensure that power can flow freely to where it is needed from resources across the rest of the region. A robust transmission system gives dispatchers the flexibility to respond to system events under critical system conditions such as summer peak load, winter peak load and light load periods.

Cold Weather Alerts and Hot Weather Alerts

Extreme weather conditions can stress the ability of the PJM system to deliver power. Such conditions are frequently characterized by high load and tight operating capacity. **Figure 23** shows the volume of hot and cold weather alerts PJM has issued each year from 2011 through 2018. Even under these stressed conditions, transmission assets in PJM continue to deliver power to both PJM customers and to neighboring systems facing their own extreme weather and peak customer demand.

Figure 23: PJM Extreme Weather Alerts



PJM issues cold weather alerts when forecasts indicate temperatures below 10 degrees Fahrenheit. PJM may also issue a cold weather alert at higher temperatures if it anticipates increased winds or projects that a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods.

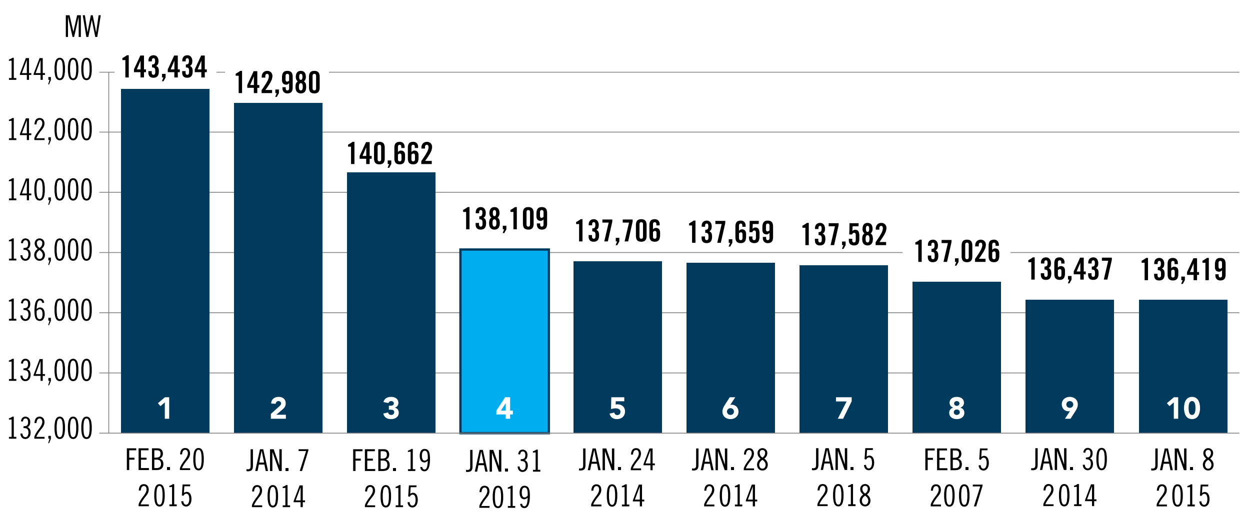
PJM issues hot weather alerts when temperatures are forecast to exceed 90 degrees[19] with high humidity for multiple days. PJM may also issue a hot weather alert at lower temperatures during the spring and fall if there are significant amounts of generation and transmission outages that reduce available generating capacity. These alerts serve to notify PJM members of higher-than-normal demand. During these periods, PJM requests that all available transmission and generation equipment be restored and that any maintenance activities planned during the alert period be deferred.

Transmission helps to maintain reliability across the PJM region – and between regions – during periods of extreme weather, when reliable power is needed the most.

Benefits by the Numbers: Weathering Extreme Conditions

During the cold snap from December 27, 2017, to January 7, 2018, PJM and its members demonstrated strong coordination and reliable operations. Few transmission concerns emerged, despite PJM experiencing prolonged cold temperatures and one of its top 10 winter peaks, as shown in **Figure 24.** In fact, PJM's robust transmission system was in a position to come to the aid of its southern neighbors. The cold weather was not isolated to the PJM footprint and extended well past PJM's southern border down through the eastern part of the country, extending into Florida. As a result, most external reliability coordinators declared a form of cold weather alert or conservative operations during the cold stretch from January 1 through January 17.

Figure 24: PJM Top 10 Winter Peaks



As of Feb. 28, 2019. This data should not be used as the basis for decision-making.

19 93 degrees in the Dominion and East Kentucky Power Cooperative TO zones.

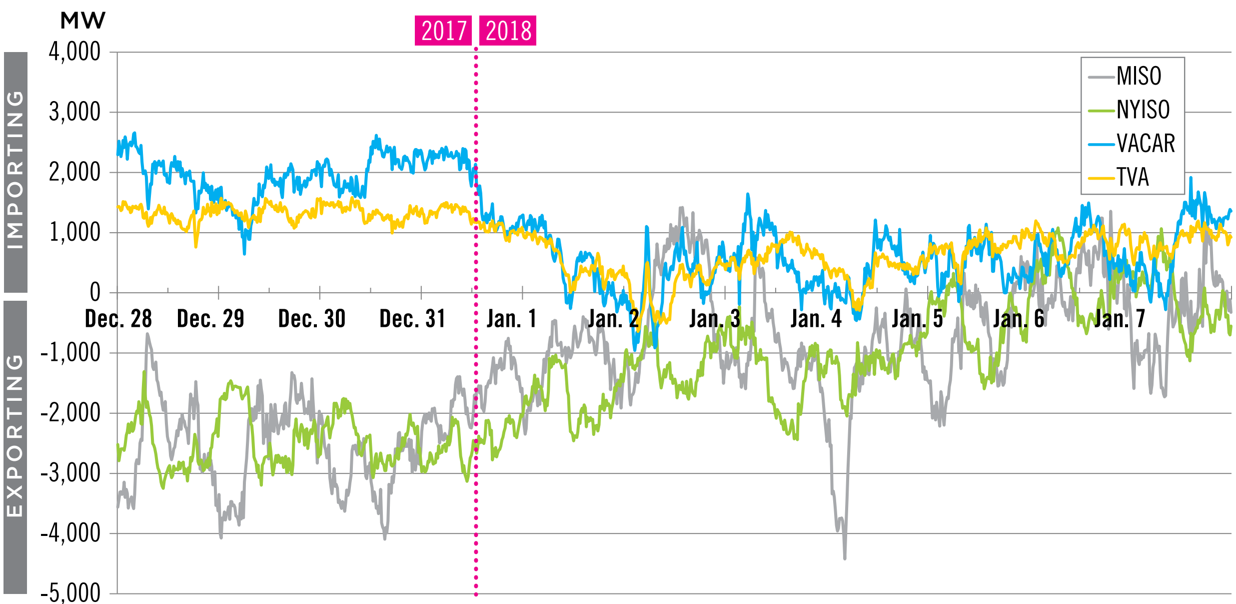
Figure 25 provides a picture of the key role transmission played during the cold snap. At the start of the cold snap, on December 28 and December 31, PJM interchange with other regions remained typical for the time of year, importing power across interregional transmission tie lines from the TVA and VACAR regions[20] to the south and exporting to MISO and NYISO. On January 1, 2018, transactions started to flow more to PJM's southern neighbors, who were experiencing some of their coldest weather and needed assistance to meet load and reserve requirements. This trend ultimately peaked on January 2, 2018, when, opposite usual patterns, PJM exported power to the south. In a corresponding trend, PJM exports to MISO and NYISO decreased.

Over the next several days, flows across interregional transmission tie lines began to return to typical levels, though southern imports had not returned to the same levels seen before the cold snap by January 7. When PJM hit a weekly peak on the evening of January 5, it was importing power from TVA, VACAR and NYISO. During that period, decreased exports and imports with MISO and NYISO were ultimately attributable to economics. PJM prices were elevated, and both MISO and NYISO, who were not in emergency conditions, found it more economical to run more internal generation instead of scheduling transactions supported by more-expensive generation from PJM.

Heavy Load Voltage Schedule Warnings and Actions[21]

In addition to cold weather alerts, PJM issued heavy load voltage schedule warnings and actions on January 4 and 5, 2018. These warnings and actions alerted TOs to energize all capacitors, remove all reactors and optimize voltage schedules to help maximize the power transfer capability of the system. By taking those steps, PJM ensured the system was positioned in the most resilient manner possible, allowing PJM to move power from one area to another if there were major generator or transmission failures. The operational flexibility of PJM's robust transmission system ensured that operational risks during this period were minimized.

Figure 25: PJM Transmission Tie Line Interchange (December 28, 2017, through January 7, 2018)



As of Jan. 31, 2018. This data should not be used as the basis for decision-making.

20 TVA is the Tennessee Valley Regional Authority. VACAR is the Virginia-Carolina region of the Southeastern Electric Reliability Council.

21 These procedures are issued proactively and do not signify any capacity or transmission concerns.

Reducing Power Delivery Constraints

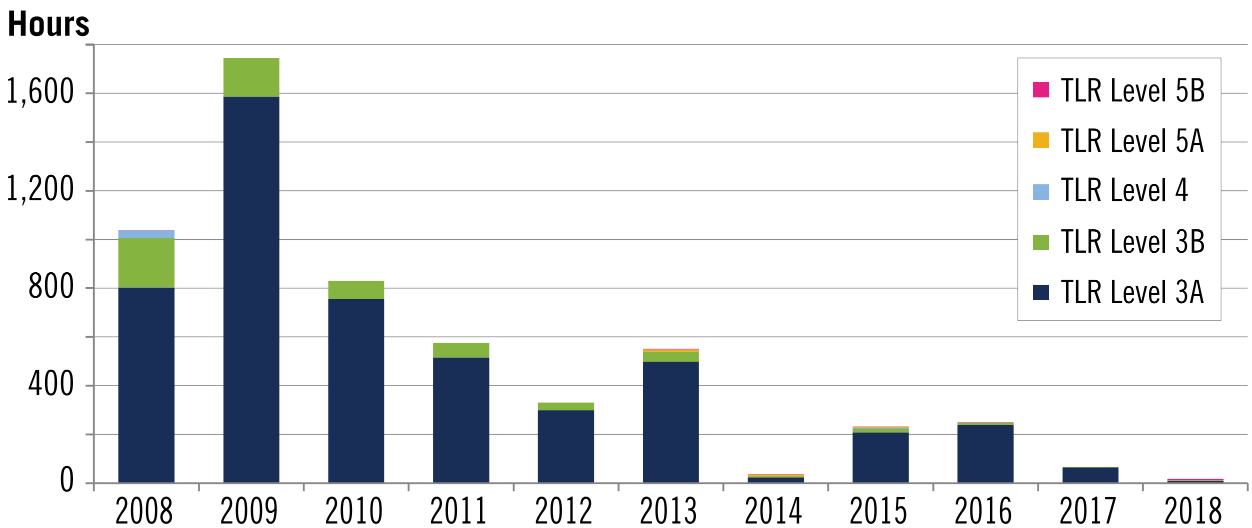
System operators have a number of emergency procedures that help ensure the reliability of the system and avoid interrupting service. A robust and well planned transmission system with new assets improves operational flexibility and efficiency. Since 2011, PJM has observed reductions in a variety of emergency procedures and alerts as well as reductions in operating limits, including interconnection reliability operating limits, remedial action schemes and more robust interchange activity with neighboring systems adjoining PJM.[22]

Benefits by the Numbers: Decreasing Transmission Loading Relief Procedures

Transmission Loading Relief (TLR) procedures[23] curtail power sales between transmission entities to manage cross-border transmission constraints, which are limitations on the ability of the transmission system to move power. PJM prefers to manage constraints by adjusting the output of generators, which is more efficient. Having fewer TLRs preserves PJM customers' interregional power purchases and sales from curtailment, which is an economic benefit. The increasing robustness of the transmission system and continuously improving interregional interoperability allow PJM operators to manage the transmission system using fewer TLR procedures.

Figure 26 makes the point. The number of hours in which PJM issued a TLR peaked in 2009 due to a congestion issue in the Commonwealth Edison (ComEd) TO zone. More than 70 percent of the nearly 1,800 total TLR hours in 2009 were a result of this issue. TLRs have steadily decreased in subsequent years. Between 2009 and 2012, ComEd re-conductored two congested 138 kV transmission lines and one 345 kV transmission line. The re-conductoring increased their emergency ratings an average of 48 percent.

Figure 26: TLR Procedure Hours (2004-2018)



As a result, congestion and TLRs decreased in 2014 and beyond. For the five years from 2014 through 2018, PJM issued TLRs totaling only 604 hours, 75 percent of which were caused by just one PJM-Duke Energy flowgate limit.

22 PJM acknowledges that generation retirement and new generation and fuel sources coming on the system shift power flows across transmission facilities. However, the consistent improvement in these various metrics also indicates that transmission system investments have been a significant contributing factor to bulk electric system robustness.

23 The NERC TLR procedure is used by reliability coordinators like PJM to hold or cut transactions in order to alleviate operating limit violations. The TLR procedure ranges from Level 1 to provide warnings or notifications to Level 6 to invoke emergency procedures. TLR Levels 3 through 5b involve cutting non-firm transactions, reconfiguring the transmission system, and cutting firm transactions, respectively. NERC's TLR procedure can be found on-line: https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Levels.aspx

Controlling Voltage

Voltage on an electric line is similar to water pressure in a hose; it is needed to ensure sufficient flow. Voltage is critical to reliable, on-demand product delivery. NERC standards require that a transmission system remain stable within applicable equipment thermal ratings and within established substation voltage ranges. Both voltage that is too low and voltage that is too high can become a serious issue, depending on the availability of resources – both generation and transmission – to produce or absorb reactive power.[24] In real-time, operators use transmission system equipment to control voltage,[25] including switching transmission lines in and out of service, switching capacitors or reactors, or adjusting voltage set points on static VAR compensators. These operator actions depend on the situation at hand, low voltage or high voltage.

Low Voltage

PJM ensures that the transmission system is able to deliver energy to areas that are experiencing a shortage. Typically, as more power is transferred across a line or set of lines, voltage levels deteriorate. The more abrupt the decline in voltage, the more difficult voltage is to control. Without adequate voltage support, power transfer increases could cause voltages to collapse after a disruption on the system. If voltage level or voltage-drop magnitude violates specified limits, system enhancements must be developed to resolve the violation.

Voltage magnitudes and voltage drop percentages are determined based on operational conditions at each substation. Voltage drop is limited to 5 percent at many 500 kV substations; emergency voltage magnitude is limited to no lower than 97 percent of substation bus voltage. If presented such a situation, system operators would have little time to react and could face the need to take quick, decisive action up to and including interrupting service without warning, an emergency procedure known as load shedding.

High Voltage

High voltage conditions usually occur during light-load system conditions, typically during the fall and spring months when customer usage is down from the peak seasons. PJM has observed load as low as 30 percent of summer peak in some TO zones. PJM's generation dispatch order during low load periods differs markedly from peak load conditions. During the past decade, significant numbers of unit deactivations have also reduced the capability of the system to absorb excess reactive power during light-load conditions.

These factors, coupled with the capacitive effect of more lightly loaded transmission lines, increase bus voltages even further. This trend is not isolated to PJM and has also been observed by neighboring systems, compounding the issue. During light-load conditions, when high voltages can be expected, PJM staff may take actions to control voltage, such as switching out capacitors, switching on shunt reactors, changing transformer tap positions, and other actions up to and including opening transmission lines. Absent such actions, high voltages can damage transmission equipment and jeopardize reliable system operation.

24 Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).

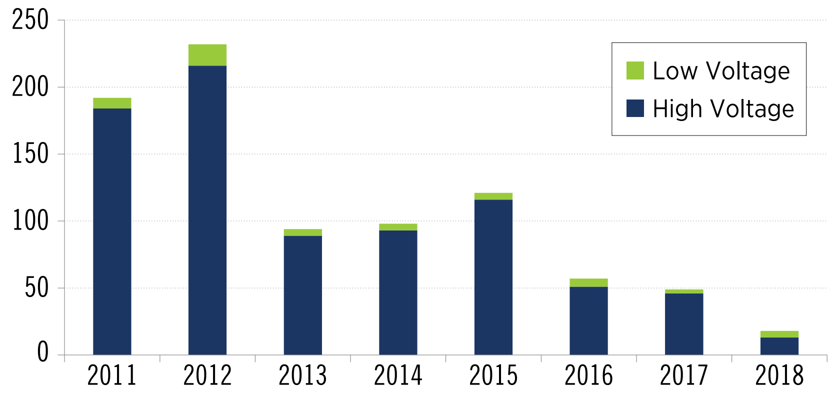
25 Voltage magnitude and voltage drop limits are defined in PJM Manual 3, Transmission Operations: https://www.pjm.com/~/media/documents/manuals/m03.ashx.

Benefits by the Numbers: Transmission Assets to Reduce High-Voltage Conditions

As **Figure 27** shows, transmission system enhancements have reduced the need for operators to implement procedures to control both high- and low-voltage conditions. More specifically, PJM's regional planning process has always included system analysis under peak load conditions, during which low-voltage criteria violations have been identified and solutions implemented over time. Identifying high-voltage conditions has been a much more recent system phenomenon, typically during periods of low customer demand. This has driven the need for new transmission assets to ensure that voltages remain under defined upper limits to prevent equipment damage that could lead to loss of transmission facilities and, ultimately, loss of customer load.

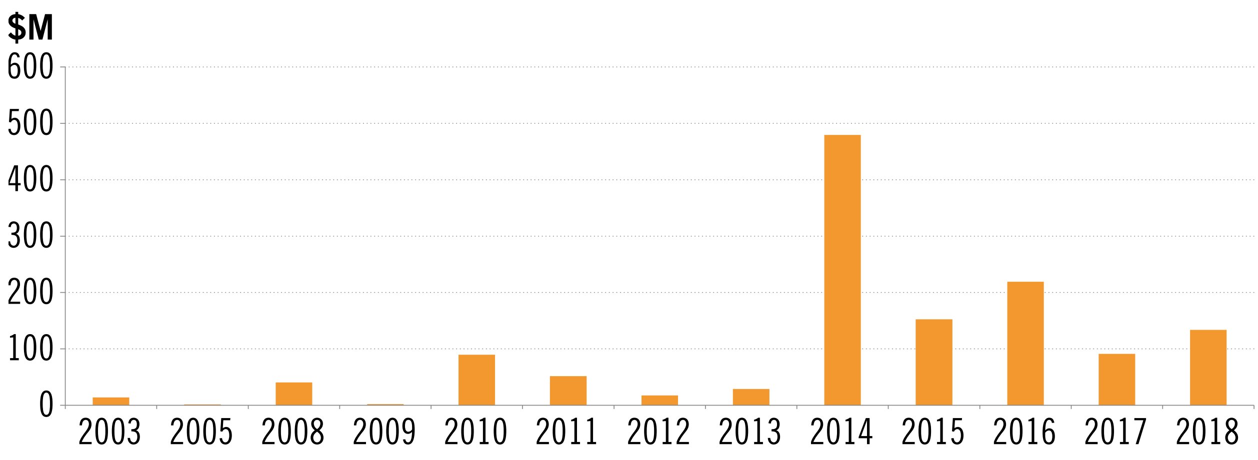
Transmission system enhancements have reduced the number of system operator actions required to ensure voltages remain within established limits.

Figure 27: Voltage Actions (2011 through 2018)

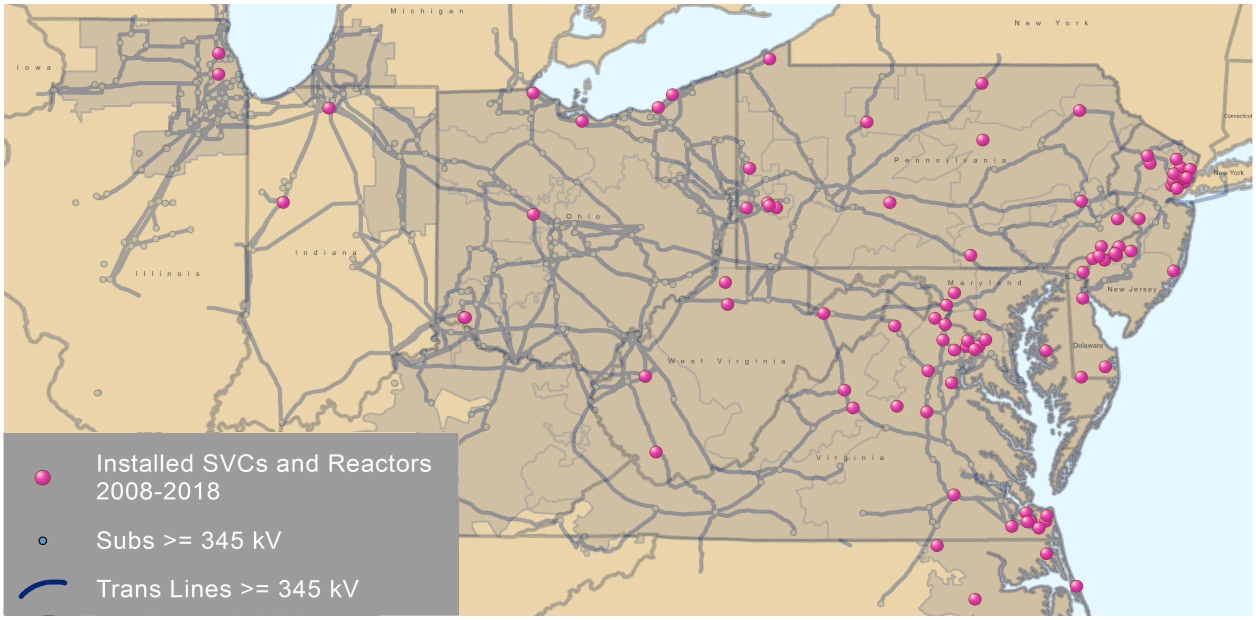


At PJM's direction, transmission owners invested more than $1.3 billion in reactors and static VAR compensators (SVCs) between 2008 and 2018 to help mitigate high-voltage system conditions (**Figure 28**). An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system performance. A reactor is installed on a transmission line to consume excess reactive power when the system is lightly loaded. These devices, described further in **Section 6**, have been installed across PJM (**Map 6**).

Figure 28: PJM SVC and Reactor Investment by In-Service Year



Map 6: Reactors and SVCs Installed in PJM (2008 through 2018)

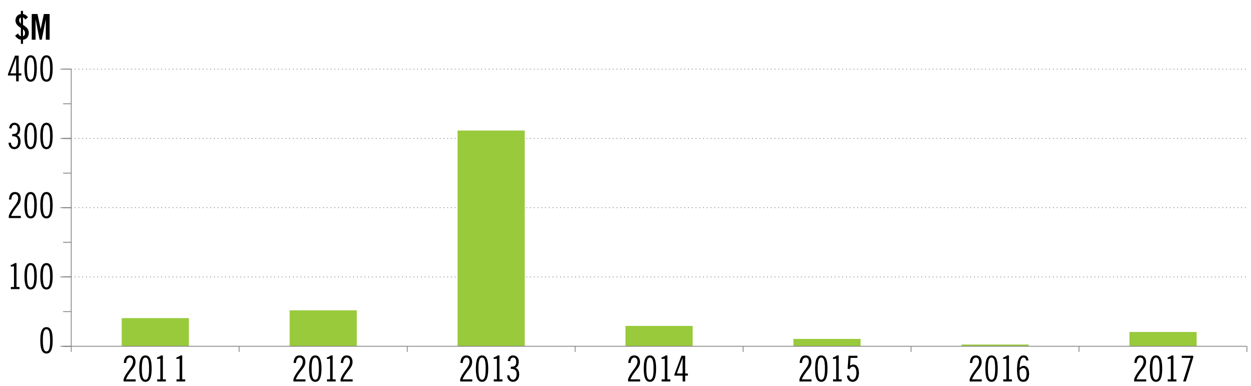


Transmission Enhancements Reduce Uplift Reactive Charges

> Transmission system enhancements reduce the number of times more-expensive generation is required to help absorb excess reactive power on the system.

The installation of additional transmission facilities that absorb reactive power has yielded more economically efficient operations as well. To control voltage violations, PJM operators may dispatch local generation to provide or absorb reactive power. In the case of high voltages, PJM has directed generation to run in order to provide reactive power absorbing capability, incurring operating reserve costs for higher-cost generators. This is reflected in higher "uplift," shown in **Figure 29** for annual reactive charges.[26] Uplift is the amount of money paid to generators to ensure they recover their cleared offer price if not covered fully by the locational marginal price (LMP). Elevated charges driven by generator retirement and associated reactive absorption capability was offset with the installation of reactors and SVCs in 2014 and beyond.

Figure 29: Annual Reactive Services Uplift Charges (2011 through 2018)



PJM notes that for the 2013 Reactive Services uplift, the DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $2.538, $1.900 and $0.690 per MWh.

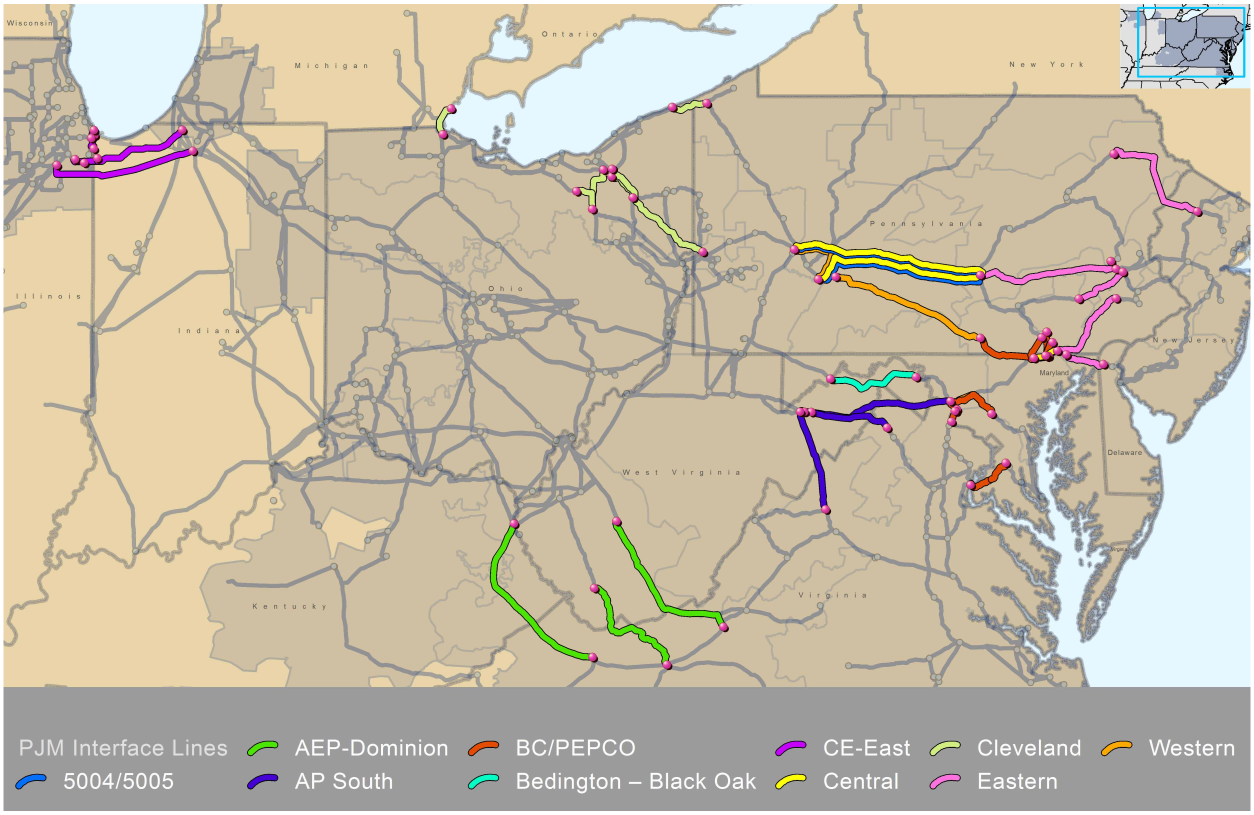
26 Data obtained from Monitoring Analytics 2018 State of the Market Report: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml

Greater Transfer Interface Margins

Since 2011, new transmission assets have notably increased the margin on the following reactive transfer interfaces (see **Map 7**):

- Eastern
- Central
- CE East
- AP South
- AEP/Dominion
- Western
- 5004/5005
- Cleveland
- Bedington-Black Oak
- BC/PEPCO

Map 7: PJM Interconnection Reliability Operating Limits



Known as interconnection reliability operating limits (IROLs), each is a group of transmission facilities. The sum of an IROL's flows must remain below a limit defined by operational study so that voltage stability is maintained in real time. In short, for a transfer level above a defined IROL, voltage collapse across the region could occur. PJM monitors IROLs and flows in real-time and studies them in day-ahead simulations to ensure voltage stability is maintained. Development of transfer interface limits is described in **Appendix C**.

Over time, PJM has observed IROL operating margins increase as a result of the additional transfer capability provided by new transmission assets. New transmission assets, by their nature, typically increase the amount of power that can flow into a TO zone to mitigate a capacity deficiency or across a transfer interface. Increasing the ability of an IROL interface to accommodate additional power flow encourages

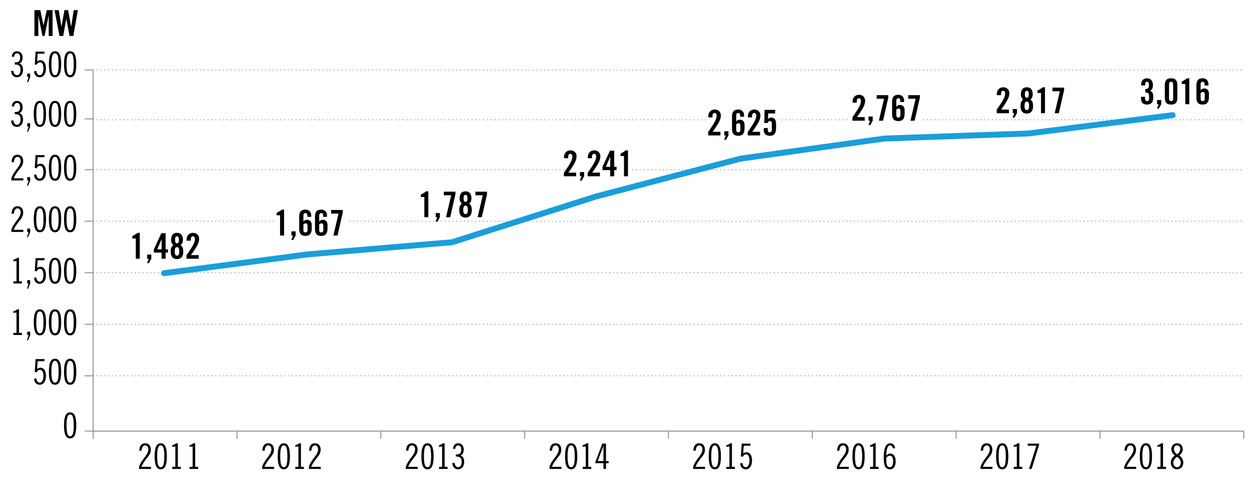
Transmission system enhancements have increased reactive transfer interface limits, giving the system greater stability and providing customers with greater access to power markets.

generator developers to locate generators where it is less costly (i.e., where transmission will not constrain unit output). Greater transfer capability increases economic efficiency through greater opportunity for bilateral power purchases and sales by participants in PJM markets. This additional capability also reduces congestion otherwise requiring the operation of higher-cost generators.

Benefits by the Numbers: Greater Transfer Interface Margin

The IROL margin is the difference between the reactive transfer interface pre-contingency flow and its IROL limit. The average margin in PJM across all IROL interfaces, as described above, was 1,482 MW in 2011, which more than doubled to an average margin of 3,016 MW in 2018 (see **Figure 30**). While generation patterns shift over time and impact the margin, new transmission enhancements have contributed to this increase as well.

Figure 30: PJM IROL Margin Improvement (2011 through 2018)



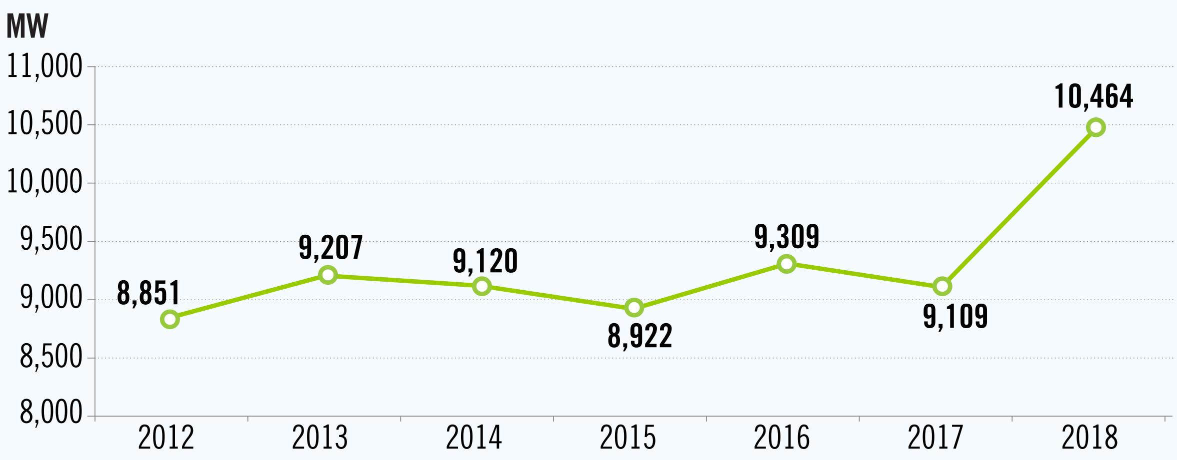
Case Study: Eastern Transfer Interface Limit Margin

PJM's Eastern Interface offers a case study that demonstrates how transmission enhancements have increased the amount of power that can be transferred across it. The ability to transfer power across that interface was boosted by the completion of the Susquehanna-Lackawanna-Hopatcong-Roseland 500 kV transmission line.

- **Hopatcong-Roseland 500 kV line –** energized April 2014
- **Susquehanna-Lackawanna 500 kV line –** energized September 2014
- **Lackawanna-Hopatcong –** energized May 2015 (final project phase)

The completion of the line in May 2015, coupled with other lower-voltage transmission enhancements in eastern PJM, has increased the transfer capability across the Eastern Interface since 2015. Between 2012 and 2018, the maximum annual Eastern Interface IROL transfer capability increased from 8,851 MW to 10,464 MW, as shown in **Figure 31.** Increasing this interface limit improves reactive stability – thereby enhancing reliability – and provides eastern PJM load centers greater access to regional power markets. Overall, the addition of new transmission assets – like Susquehanna-Roseland in this case – also increases the robustness and resilience of the PJM grid.

Figure 31: Maximum Annual Eastern Transfer Interface IROL (2012 through 2018)



Case Study: Cleveland Transfer Interface Limit Margin

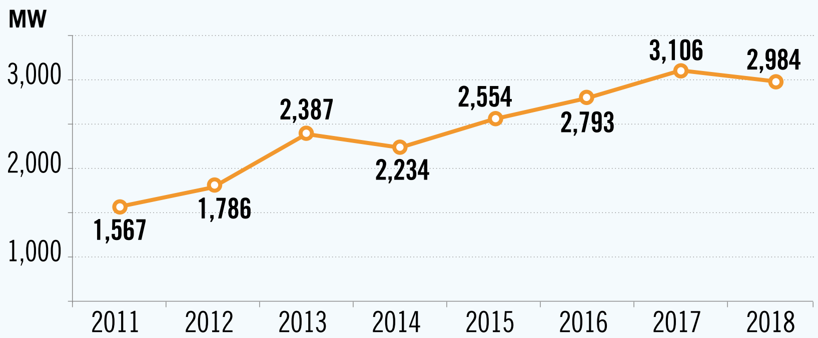
The Cleveland Transfer Interface provides a case study of the benefits of transmission system enhancements. In this instance, the PJM Board-approved RTEP system enhancements shown in **Table 5** and **Map 8** have increased Cleveland Transfer Interface capability as shown in **Figure 32.** As with the Eastern Interface discussed earlier, increasing this interface limit improves reactive stability, thereby enhancing reliability.

The additional interface margin alleviates the need for system operators to dispatch generators out of economic merit order to control actual interface power flow, incurring congestion costs. Overall, the addition of new transmission assets like those in **Table 5** increases the robustness and resilience of the PJM grid.

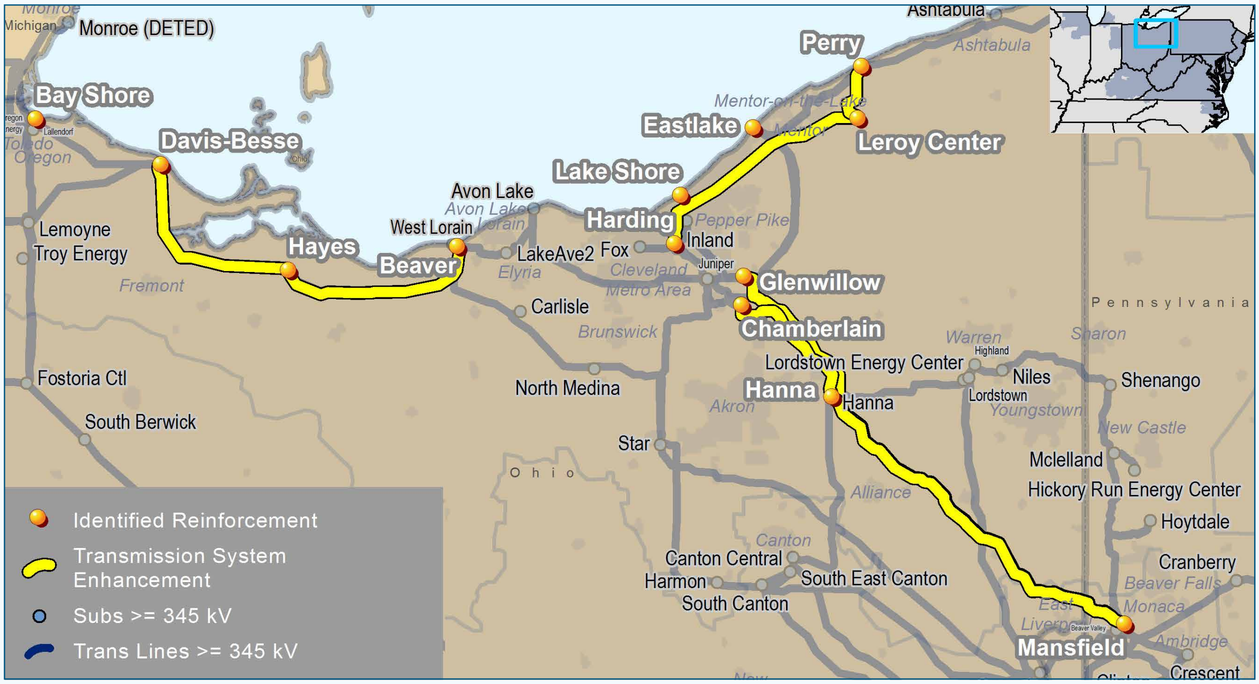
Table 5: Cleveland Transfer Interface Area System Enhancements (2014-2016)

Upgrade	In-Service Date (Month/Year)
Mansfield-Glen Willow 345 kV line	June 2015
Second Davis Besse-Hayes-Beaver 345 kV	June 2014
Mansfield-Chamberlin 345 kV line loop into Hanna	June 2014
A new Leroy Center station splitting the Perry-Harding 345 kV line, with two 345/138 kV transformers installed at Leroy Center	June 2016
Lakeshore SVC	June 2015
Eastlake units converted into synchronous condensers	July 2013-May 2016 (in phases)
Second Bay Shore 345/138 kV transformer	May 2014

Figure 32: Cleveland Transfer Interface Average Annual IROL (2011 through 2018)



Map 8: Cleveland Transfer Interface Area System Enhancements (2014-2016)



Increasing Operational Flexibility

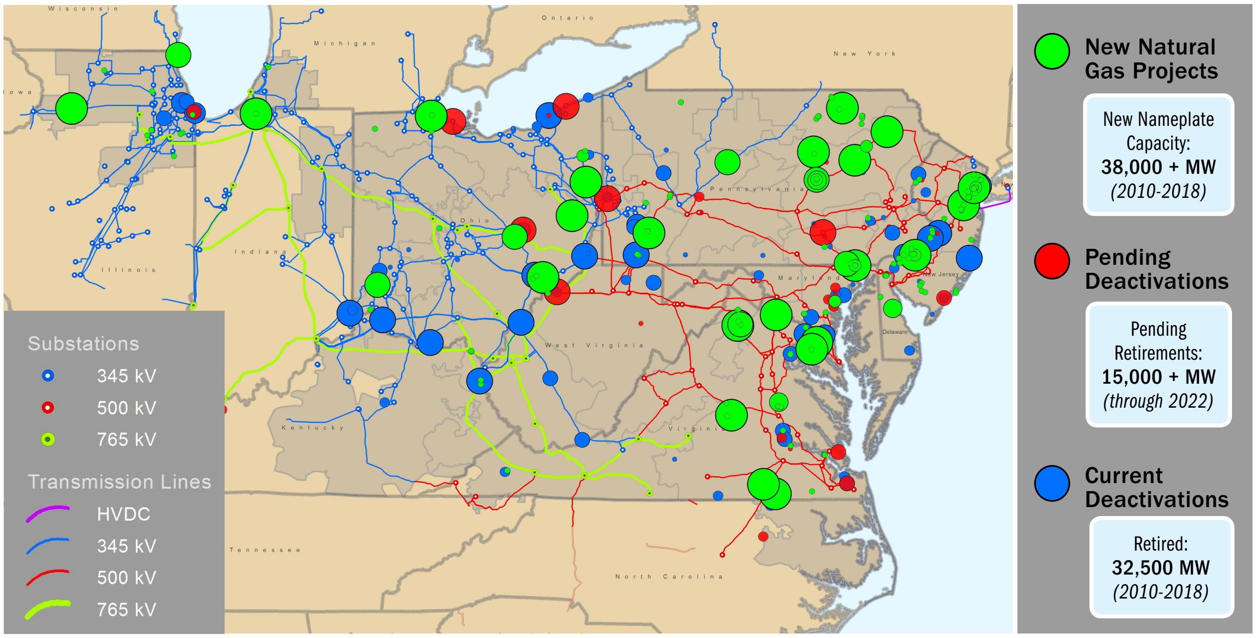
West-to-East Power Flows Are Shifting

Transmission assets are accommodating a historic fuel shift while keeping the system reliable.

Historically, power flow across PJM transmission lines has generally been from west to east. High-voltage transmission assets were approved to deliver lower-priced western PJM coal-fired generation reliably to eastern PJM load centers. This power flow is changing. The combination of generation retirements across the PJM footprint coupled with the increase of natural gas generation in the east is driving a shift on some transfer interfaces, as shown in **Map 9**. PJM has observed more power flow "push" from east to west.

The operational flexibility of these transmission assets is responsible for encouraging new generation within PJM's footprint, particularly natural gas-fired generation using Marcellus and Utica shale gas. In other words, transmission assets are accommodating a historic fuel shift while keeping the system reliable. Transmission is assisting this shift by allowing more generators to compete so that the lowest-cost generation serves customer load, no matter where it is in the PJM footprint.

Map 9: Generation Entry and Exit Since 2010



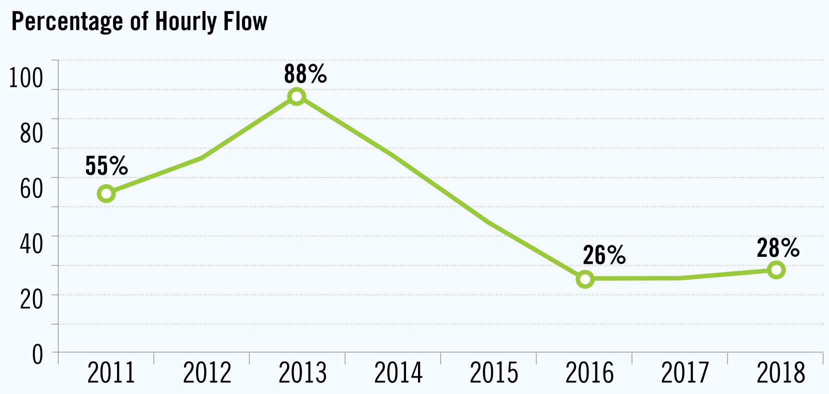
Case Study: Central Interface Operational Flexibility – East-to-West Power Flow

The Central Transfer Interface provides a good example of the shift in flows over time, as shown in **Figure 33**. The average hourly flow from west to east was up to 88 percent of all hours in 2013. By 2018, only 28 percent of hours were west to east. During the other 72 percent, power flowed from east to west.

Removing Need for Remedial Action Schemes

New transmission system enhancements are mitigating the need for Remedial Action Schemes (RAS)[27] across PJM. A RAS device is an assembly of power system protection equipment designed to detect and initiate an automatic action in response to abnormal or pre-defined system conditions, for example, tripping generation for the loss of one or more area transmission lines to prevent generator instability. New transmission assets mean that these schemes can be retired without jeopardizing reliability and without interrupting load or tripping generation. Across the industry, RAS devices have also been subject to misoperation, causing significant system events. PJM periodically evaluates RAS installations to identify which ones may no longer be needed, the result of various reasons including:

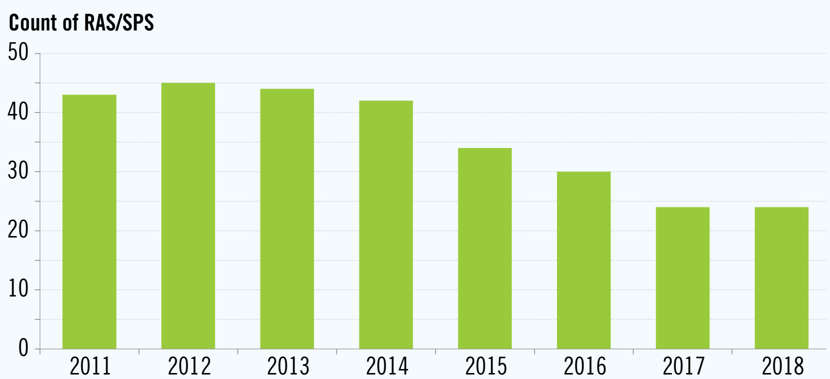
Figure 33: Average Hourly Pre-Contingency West-to-East Power Flow



- RAS need has been mitigated by an RTEP project that has reached in-service status.
- The reliability issue that the RAS was designed to address no longer exists.
- System changes have mitigated the congestion the RAS was designed to address.
- The RAS has not been activated for several years.

As a result of transmission system enhancements, the number of active RAS devices has been decreasing, as shown in **Figure 34**. From 2012 to 2018, the number of active operational schemes decreased from 45 to 24; 21 schemes were retired or reclassified.

Figure 34: Remedial Action Schemes Across PJM - Year-End Count



27 Formerly known as Special Protection System (SPS), a RAS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switch gear auxiliary switches, and all associated connections. A RAS is intended to protect equipment from thermal overload or to protect against system instability stemming primarily from scheduled or forced transmission outages. A number of such systems exist across PJM, originally installed by utilities themselves as a solution to extraordinary transmission outage conditions.

Case Study: Reducing the Need for Remedial Action Schemes

Dominion installed the North Hampton RAS to mitigate potential uncontrolled power interruptions under certain generation and transmission outage conditions. Under this RAS, controlled power interruptions to approximately 950 MW of customer load during peak periods, including over 150,000 customers, would be implemented to maintain grid reliability. With the recent completion of the Skiffes Creek transmission project, the North Hampton RAS can be retired, eliminating the risk of shedding that load.

Interregional transmission ties enable rapid emergency support between PJM and its neighbors.

Interregional Ties Support Reliable Operation

Robust transmission tie lines allow PJM and its neighbors to rely on one another during stressed system operating conditions, which can allow the system to recover from a loss of generation or supply power during peak demand periods.

Case Study: Shared Reserve Activation with NPCC

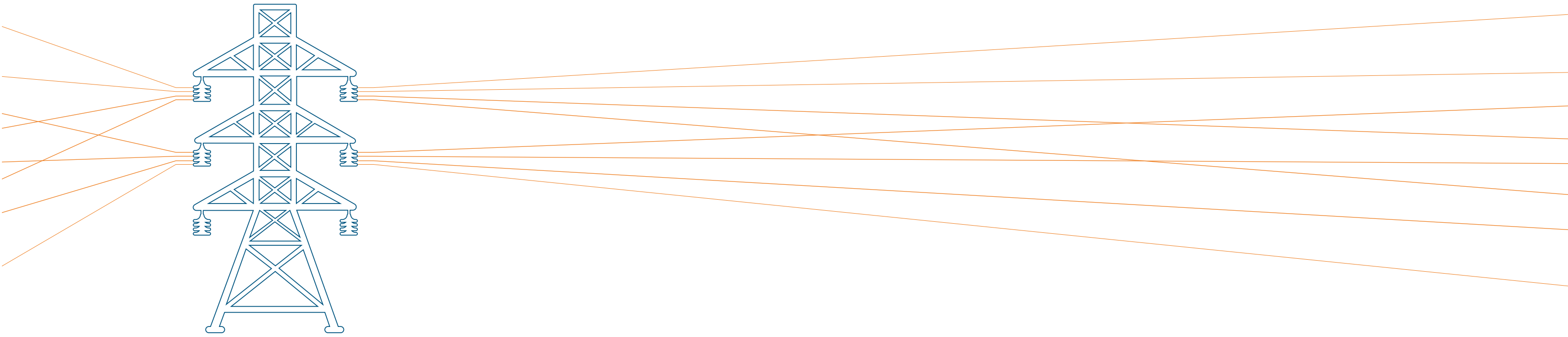
Disturbance recovery is essential for system reliability and meeting NERC standards. Having the ability to transmit power to a neighbor with only a few minutes' notice helps restore system frequency and area control. Transmission makes this possible. PJM participates in reserve-sharing agreements with neighboring systems to assist both PJM and its neighbors with recovery from disturbances, including, in many instances the loss of a generators greater than 500 MW.

PJM's interregional agreement with the Northeast Power Coordinating Council (NPCC) includes provisions for shared reserves to help with disturbance control. This permits PJM to recover from an imbalance between supply and demand faster than with internal reserves alone. The help is reciprocal, and PJM provides NPCC with shared reserves when called upon. **Table 6** shows the number of times per year PJM operators have implemented shared reserve actions, enabled by PJM transmission tie lines with NYISO.

Transmission system enhancements have reduced the number of protective Remedial Action Schemes on the system improving reliability and operating flexibility by removing automatic generation and load trip conditions.

Table 6: NPCC Shared Reserve Activation

Year	No. of Events During Which PJM Received Shared Reserves from NPCC
2011	6
2012	3
2013	4
2014	10
2015	6
2016	4
2017	1
2018	7



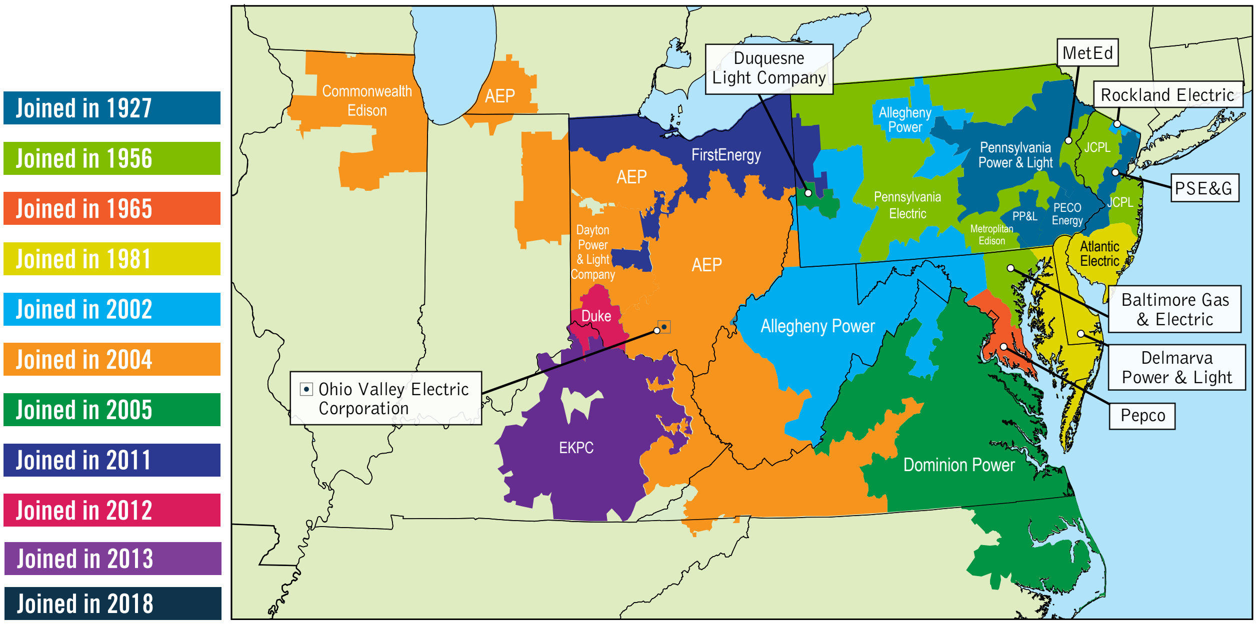
Section 5 Access to Lower-Priced Energy

Transmission enables the lowest-cost power to reach the greatest number of people. PJM is made up of many transmission zones and is interconnected to power systems adjoining PJM. PJM system operators schedule and dispatch the lowest-cost power resources to generate electricity, regardless of which transmission zone or state it comes from, incrementally adding more expensive resources as they're needed and saving the highest-cost resources for relatively brief periods of peak customer demand. This allows low-cost power to flow into, out of and through PJM across transmission lines that allow generation inside and outside of PJM to participate in the wholesale markets, which increases competition, lowering costs.

Transmission assets tie PJM zones together. These assets enable competition among power producers by providing access to PJM's wholesale markets for capacity, energy and ancillary services. For example, billings in 2018 totaled $49.8 billion for energy totaling 806,546 GWh. Markets lower the net costs of electricity to consumers by allowing the lowest-cost megawatts available at any given moment to be dispatched across transmission tie lines for customers to use. Doing so reduces overall production costs and load payments, as discussed later in this section.

> Transmission allows the free flow of electricity between PJM and other regions, enhancing reliability and keeping costs low.

Map 10: PJM Market Integration History



Since 2002, PJM has added seven transmission zones to its original footprint (see **Map 10**). This has enabled the addition of 112,000 MW of generation and 95,000 MW of peak customer demand, increasing competition in wholesale power markets and providing lower wholesale prices to consumers.

Transmission Across PJM Borders

PJM operators coordinate the flow of power across transmission lines that link individual utilities inside PJM and across transmission tie lines to adjoining systems:

- **North** – New York Independent System Operator (NYISO) and through it, the Independent System Operator of New England (ISO-NE) and Canadian utilities
- **West** – Mid-Continent Independent System Operator (MISO)
- **South** – Tennessee Valley Authority (TVA), Duke Energy Progress of North Carolina, and Louisville Gas and Electric

> Interregional transmission lines improve reliability through access to additional generating capacity.

Coordination agreements between PJM and these systems specify the obligations to which all parties are committed in order to preserve reliability under defined emergency conditions and coordinate economic power transactions for the benefit of respective market participants.

Interregional transmission tie lines allow PJM market participants to buy and sell power with parties outside the PJM control area. The schematic superimposed over PJM and the eastern U.S. in **Map 11** emphasizes the extent to which PJM coordinates these transactions with other control areas in the Eastern Interconnection.

Map 11: Coordinating Interregional Power Sales and Purchases

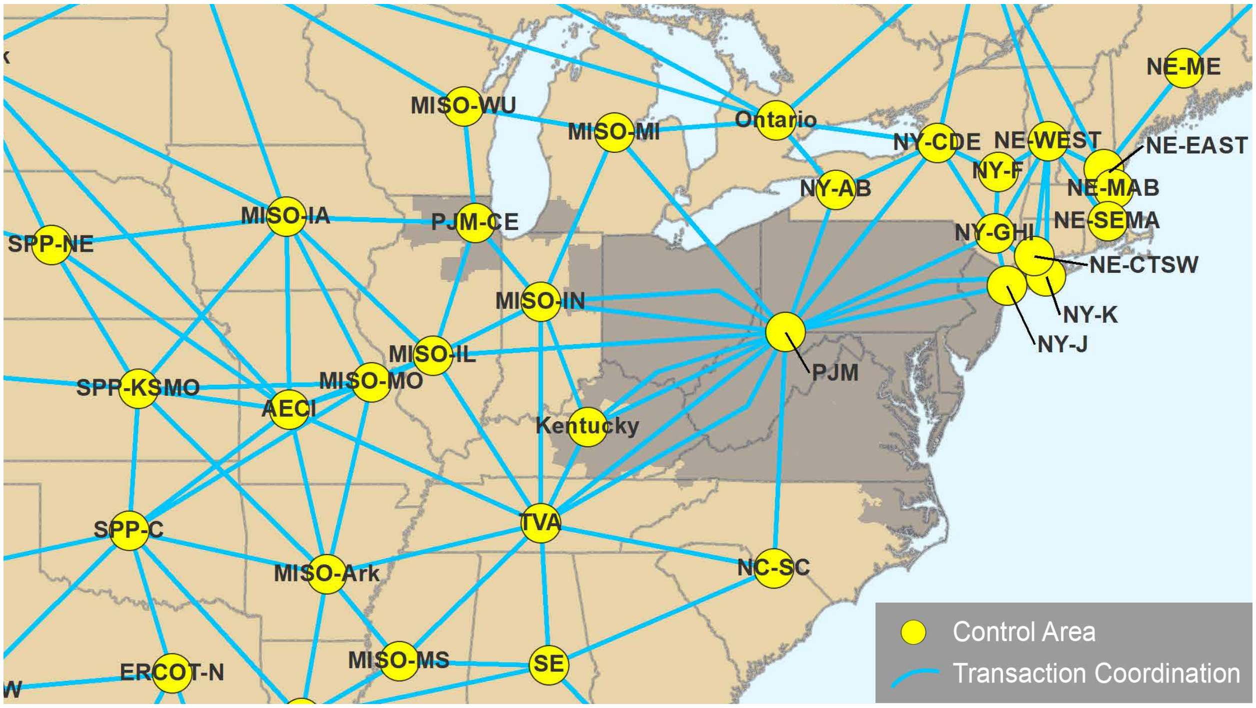
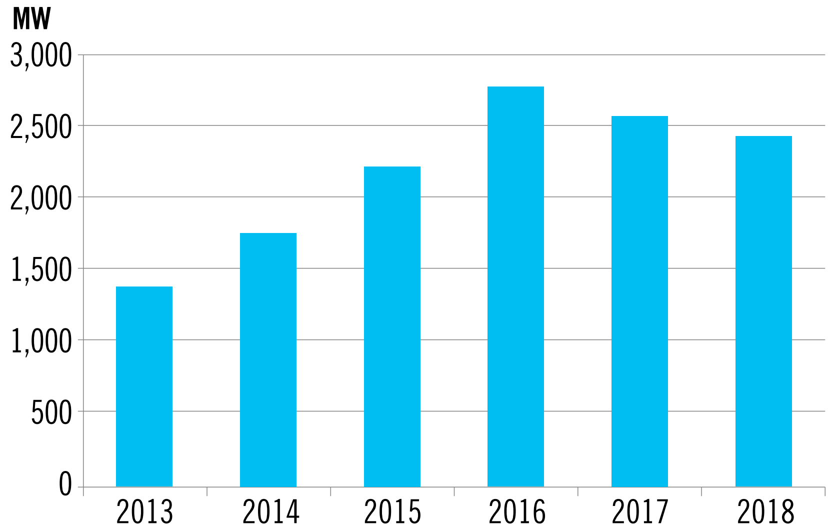


Figure 35: Average Hourly Scheduled Interchange (Gross)



The ability to schedule power transfers across interregional tie lines promotes economic efficiency. Bilateral transactions, those that occur exclusively between buyers and sellers, allow load-serving entities – and third-party traders – to pursue opportunities from generators outside of PJM. **Figure 35** shows the average hours of scheduled interchange – on a gross basis – from 2013 through 2018. Interregional transmission tie lines permit external generators to be "pseudo-tied" to PJM and participate in PJM's capacity, energy and ancillary services markets as if they were inside PJM's footprint. By doing so, they enhance reliability. Since 2016, PJM has integrated over 5,000 MW of pseudo-tied generation into and out of PJM, accounting for the decrease in scheduled interchange since 2016 shown in **Figure 35**. Operationally, these resources are treated as internal resources. None of this would be possible without the transmission lines that link PJM with adjoining systems.

Enhancing Energy Market Efficiency

A Fluid Market

Transmission enables the lowest-cost power to reach the greatest number of people. PJM operates the grid by scheduling and directing the lowest-cost power resources to generate electricity first, incrementally adding more expensive resources as they are needed and using the highest-cost resources during the relatively brief periods of peak customer demand.

Throughout the year, market economics can shift (even from hour to hour) across all 8,760 hours of a year. Fuel prices fluctuate, generation resources go in and out of service for maintenance, new generation resources are commissioned and old ones retire. The transmission system enables PJM to handle this highly fluid wholesale energy market, transporting the lowest-cost power across the region and giving all generation resources, regardless of fuel type, access to the market.

Impact of Congestion

Ratings on transmission system equipment limit the operation of a facility, whether it be the amount of power flowing on it, the voltage it can support, or the circuit-breaker short-circuit fault current it can interrupt. When the transmission system is constrained, those limits can be reached and operators must reroute power flow by deploying higher-cost generating units to avoid overloads and risk losing transmission equipment. This re-dispatch yields less-efficient production of electric power, which adds congestion costs, which can increase the cost to consumers. Increasing the transmission system's capacity with investment in the system can decrease congestion costs and save consumers money.

Congestion Relief Provided by New Transmission

Congestion reduction is achieved one of two ways:

1. As a major ancillary benefit to transmission projects whose need was justified to prevent overloads
2. Specifically to provide economic benefit that exceeds cost by at least 25 percent

Either way, benefits may include reductions in production cost and load payments:

- Production costs represent the fuel costs, variable operating and maintenance costs, and emission costs of dispatched resources in PJM. Production cost savings represent system-level benefits. New transmission can reduce the variable cost of generation supply to the market.
- Load payments represent the cost, measured by LMPs, for the energy supplied to the consumer. Load payments are directly affected by the quantity of energy and the price.

Transmission enhancements in PJM are estimated to reduce costs to customers by more than $288 million a year by alleviating congestion.

Benefits by the Numbers: Economic Benefit of Approved Transmission Projects

As part of quantifying the value of transmission, PJM conducted a production cost analysis to assess the economic benefit provided by new transmission assets. An energy market simulation tool was used to model the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. The general scope and procedure for this analysis is provided in **Appendix D.** A detailed generation, load and 2019 study-year transmission system model was used as input in order to simulate hourly generation commitment and dispatch to meet load, while recognizing the physical limitations of the transmission system.

PJM then compared market simulations with and without RTEP Board-approved transmission projects with in-service dates from 2014 through 2023 that had analytically already yielded congestion reduction over a one-year period. **Table 7** presents annual congestion cost study results for a sample of 10 constraints that yielded significant congestion-cost reduction subsequent to the in-service-year date for each project.

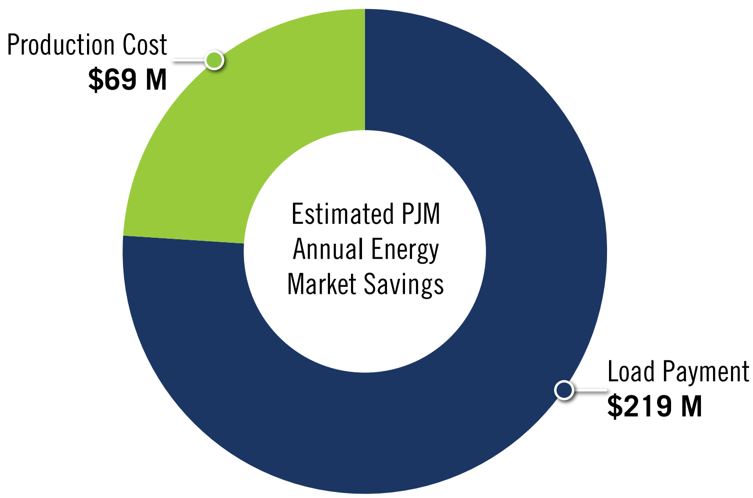
Table 7: Production Costs Analysis Results – Annual Energy Market Savings from New Transmission Assets

Project Description	TO Zone	Project In-Service Year	Annual Congestion ($M)				
			2014	2015	2016	2017	2018
Rebuild Mt Storm-Doubs transmission line	APS, DOM	2014	$5	$0	$0	$0	$0
Construct a Susquehanna-Roseland 500 kV circuit	PPL	2015	$21	$22	$1	$1	$4
Reconductor the Burlington-Croydon circuit	PECO	2015	$11	$2	$0	$0	$0
Convert the Bergen-Marion 138 kV path to double circuit 345 kV	PSE&G	2016	$22	$28	$0	$0	$0
Add two additional 345/138 kV transformers at Kammer	AEP	2016	$3	$8	$9	$1	$1
Upgrade the Mill T2 138/69 kV transformer	AECO	2016	$1	$1	$5	$0	$0
Rebuild Graceton-Bagley 230 kV as double-circuit line	BGE	2017	$107	$104	$144	$7	$11
Construct a new Byron-Wayne 345 kV circuit	ComEd	2017	$16	$8	$18	$8	$0
Loop the TMI-Hosensack 500 kV line into Lauschtown substation	METED	2017	$1	$8	$10	$14	$2
Rebuild the Wattsville-Kenney-Piney Grove 69 kV line	DPL	2018	$13	$4	$8	$14	$0

Congestion cost prior to project in-service dates

The results of this production cost analysis show that in the PJM Energy Market alone, the transmission enhancements approved between 2014 and 2023 are estimated to reduce costs to customers by more than $288 million in combined annual load payments and annual production costs, as shown in **Figure 36.** Transmission enhancements remove market inefficiencies manifested by persistent congestion – as described above – to allow greater access to lower-cost generation.

Figure 36: Energy Market Savings Production Cost Analysis Results

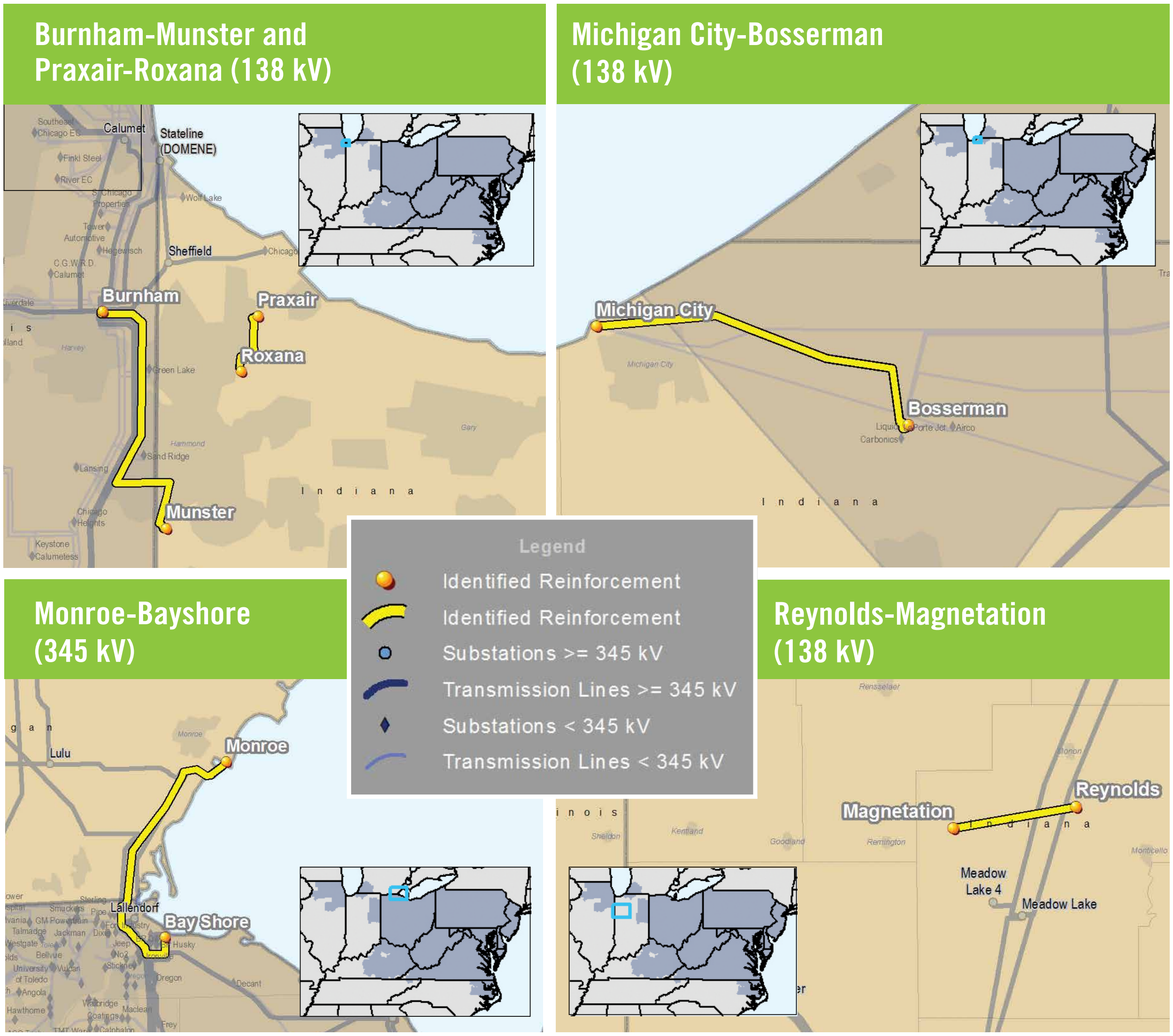


Benefits by the Numbers: PJM/MISO Targeted Market Efficiency Projects

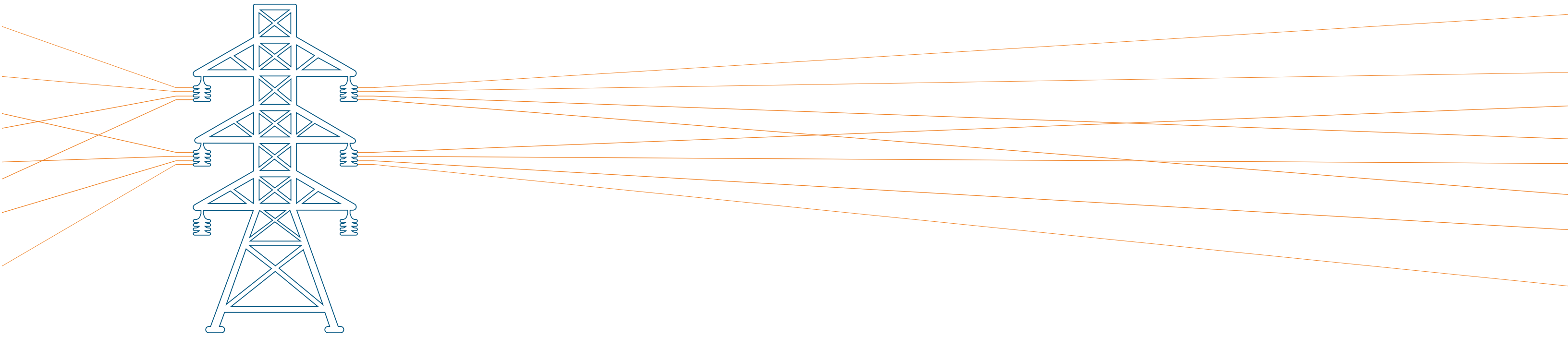
PJM customers also benefit from new transmission assets that reach into neighboring regions. In December 2017, the PJM and MISO Boards approved a portfolio of five targeted market-efficiency projects (TMEPs) to address historical congestion along the PJM/MISO boundary (see **Map 12**). TMEPs are focused on developing low-cost, short lead-time, high-impact projects to address market-to-market congestion. TMEP projects must yield four-year market congestion savings[28] that are equal to or greater than the estimated project capital cost. The total capital cost for the five projects is approximately $20 million, with an estimated congestion savings benefit of $100 million over the first four years of commercial operation.

New interregional transmission assets will produce estimated congestion savings of more than $100 million in the first four years alone.

Map 12: PJM/MISO Approved Targeted Market Efficiency Projects



28 As defined in the PJM/MISO Joint Operating Agreement.



Section 6 Grid Modernization

Modernizing the existing transmission system will provide benefits, including designs that can withstand more extreme events, lower the frequency and shorten the duration of outages, reduce public and employee safety risks, and use advanced technology to improve system operability, efficiency and security. A modernized system will ensure a future characterized by enhanced reliability, cost savings and environmental and societal benefits, whether driven by new technologies, aging infrastructure, asset management processes, resilience, FERC action or other factors.

Asset Management — Aging Infrastructure

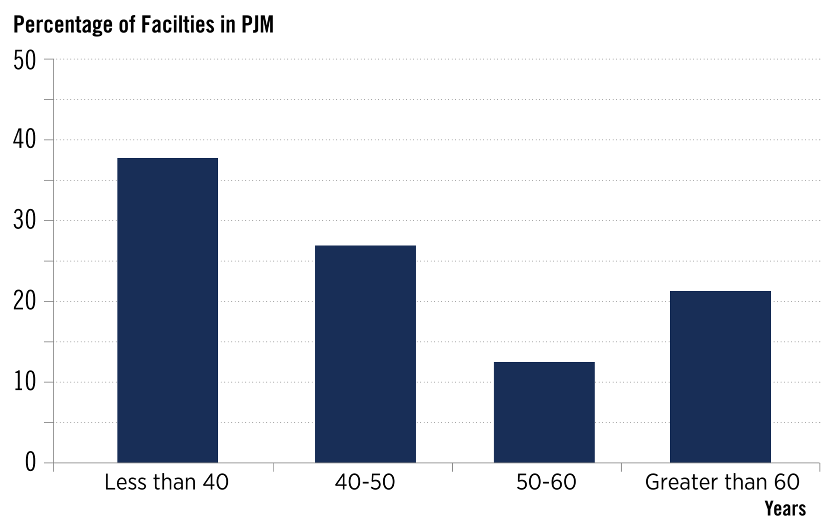
The regional high-voltage transmission system is aging; many facilities were placed in service in the 1960s or earlier. They are deteriorating and reaching the end of their useful lives. Maintaining older equipment means higher costs and greater risk of outages. Addressing this deterioration and the associated costs and risks is part of each transmission owner's broader asset management strategy, as described in **Appendix E.** As equipment continues to age, the approach must shift from simply maintaining assets to replacing and modernizing them. Asset modernization has gone beyond replacement. Replacement projects offer the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when original facilities were built.

> Old transmission equipment deteriorates with age. Two-thirds of transmission in PJM is more than 40 years old and must be replaced to ensure reliability and reduce elevated maintenance costs.

By the Numbers: Aging Infrastructure

Nearly two-thirds of all bulk electric system assets in PJM are more than 40 years old and more than one-third are more than 50 years old (**Figure 37**). Some local, lower-voltage equipment, especially below 230 kV, is approaching 90 years old. Most of this equipment – cable, tower structures and tower foundations, for example – is outdoors and deteriorates with age. Some tower structures – often at 115 kV and 138 kV voltage

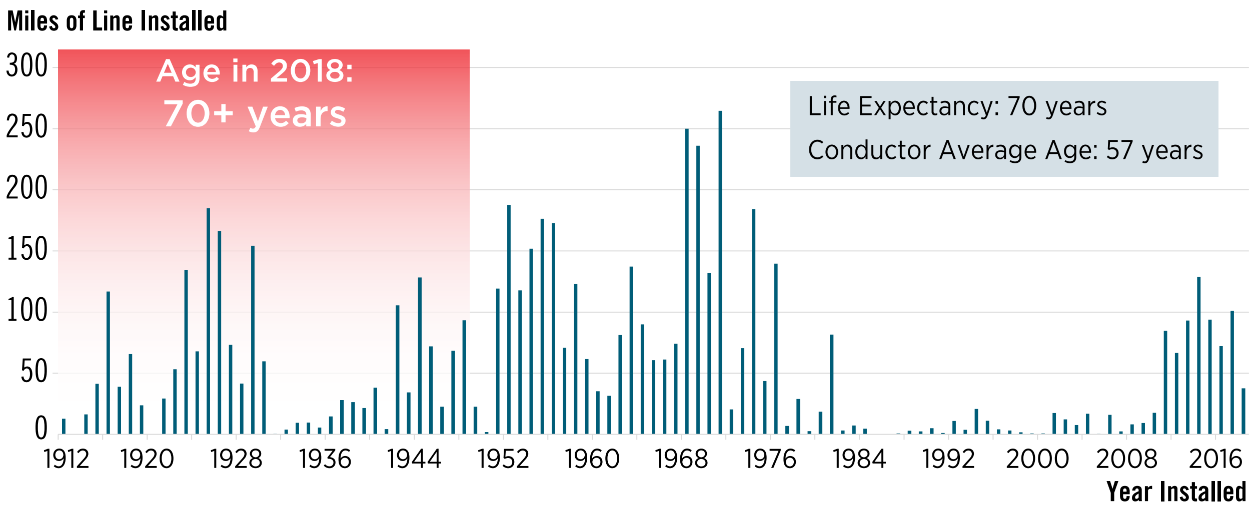
Figure 37: Aging Bulk Electric System Facilities in PJM



levels – were originally constructed of wood and have begun to deteriorate. Other structures originally constructed of iron exhibit significant rusting and degradation. Loss of structural integrity subjects transmission lines to increased maintenance costs and reliability risks.

Figure 38 drives the point home. It shows an example of an aging transmission profile, (in this case, AEP transmission lines in Ohio). Some of these transmission lines date back to 1912. Several thousand miles of transmission lines were built before 1948, which is older than the 70-year life expectancy of a typical line. Overall, a 57.1-year average conductor age demonstrates the growing reliability concerns caused by aging assets, a concern that can be solved by replacement with new transmission assets.

Figure 38: Example Aging Assets Profile – AEP Ohio Footprint in PJM



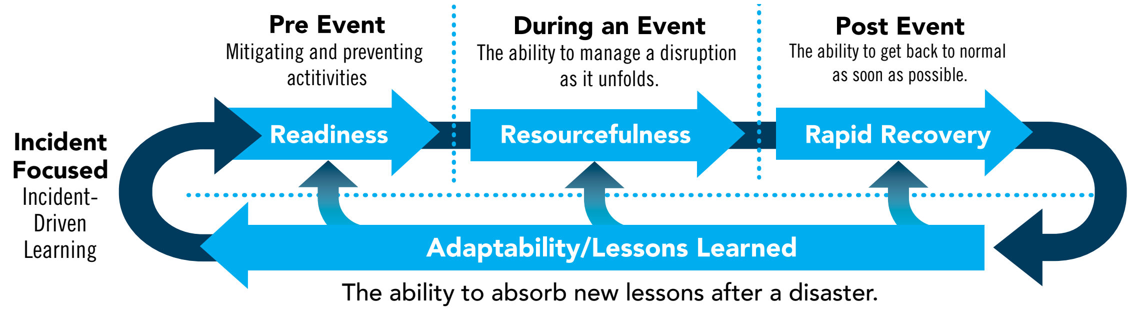
Enhancing Resilience

Operators of the world's electrical grids are contending with a range of emerging challenges, including extreme weather, cyber and physical attacks, changes in the electric generation fleet driven by cheap and plentiful natural gas, and increased deployment of renewable resources. The pace of those changes has pushed grid operators to prepare for future vulnerabilities for which no set of standards currently exist.

To be resilient, PJM must prepare for, operate through and recover from threats, as depicted in **Figure 39**:

- **Pre-event.** Prepare: Anticipate, evaluate and cost-effectively mitigate risks
- **During an event.** Operate: Manage through a high-impact disruption
- **Post-event.** Recover: Regain essential functions as rapidly as possible

Figure 39: Defining Resilience



PJM's operations, planning, markets, physical security and cybersecurity functions are part of ongoing collaborative, organization-wide efforts to establish processes, develop tools and enhance communications to maximize grid resilience. PJM has initiated efforts to implement planning-process criteria and metrics to enhance grid resilience beyond the measures in place today.

The Role of Transmission in Resilience

For decades, planning criteria has been developed and applied to power systems around the world to ascertain the need for new transmission. This provides a robust grid so that system operators can address various operating scenarios on any given day. Planners test the system under simulated stressed conditions – extreme weather conditions, for example – to understand where reinforcements are needed to make the grid reliable.

NERC planning criteria require that the bulk power system be tested for such contingencies as the loss of a transmission line – a high probability, low impact event – under the assumption that every other transmission facility is in service. Yet in reality, dozens of facilities are out of service on the system on any given day. PJM also simulates more severe, lower-probability events like multiple facility outages. These include the loss of two circuits on a common tower line or a fault on a circuit followed by a breaker failure or two unrelated contingencies, otherwise known as the "n-1-1" test.

NERC standards address resilience to a degree. Planning standards also require examination of the impact of extreme events such as the loss of an entire substation or the loss of an entire right-of-way caused by a landslide, tornado or fire, taking down multiple transmission lines in one corridor. Although an assessment of the impact of these events is required, reinforcement for these low-probability events is not required under current NERC criteria.

Reliability criteria are structured around likely events. Planners must also assess whether the transmission system is sufficiently reinforced to address extreme events such as physical and cybersecurity attacks or extreme weather conditions like hurricanes.

Resilience: Taking Reliability a Step Further

Resilience and reliability both seek to keep the lights on but are not conceptually the same. PJM already complies with established NERC, regional and TO reliability standards. To that end, PJM conducts its planning studies under critical, stressed conditions so that system dispatchers can manage the actual system conditions on any given day in real time. Resilience takes this to another level, addressing challenges and emerging risks that existing reliability standards do not fully capture:

- Maintaining reliability in the face of significant events
- Evaluating threats as part of the TEAC process
- Slowing disruptive events, mitigating their impacts and quickly recovering essential functions
- Protecting essential systems based on assessed risks and hazards
- Improving grid flexibility and control to adapt efficiently and quickly to post-event conditions

PJM has initiated efforts to implement RTEP process criteria and metrics in order to enhance grid resilience beyond that in place today. The NERC CIP-014[29] standard requires TO assessments to identify critical facilities that, if rendered inoperable, would cause instability, uncontrolled separation or cascading outages.

29 https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-1.pdf

PJM experience suggests that developing RTEP projects in response to resilience criteria could be accomplished through three decision-making approaches:

1. **Do no harm,** so that the solution to an identified reliability criteria violation does not introduce new resilience issues.
2. **Leverage project opportunities** already identified under reliability, market-efficiency needs or public policy needs to enhance resilience.
3. **Respond proactively** with new projects to mitigate resilience risks.

Identifying RTEP resilience solutions must balance cost and benefit. All facilities cannot be hardened against all contemplated threats and risks. Defining benefits and values will require comprehensive new RTEP process metrics – both stochastic and deterministic – and the requisite tools to calculate them. Under each approach, metrics are required that assign a resilience score to every transmission facility – substation, line and transformer, based on criticality, for example. System resilience is a key consideration in the evaluation of planning solution alternatives so that PJM can select solutions that enhance resilience as part of addressing other criteria violations or as stand-alone criteria itself.

Resilience vulnerabilities that are significant enough to warrant a transmission system enhancement could be designed to be integrated into PJM's RTEP. For example, this could include building redundancy into black start generation cranking paths, reducing the criticality of substations through transmission line siting and power flow diversity for areas with load congestion or high concentrations of critical restoration generating units.

While PJM continues to pursue formal implementation of these transmission planning approaches, parallel transmission resilience initiatives continue in several areas: spare transformer need, phasor measurement unit implementation and cascading event analysis tool development.

Benefits by the Numbers: Spare Transformers

As the electric transmission system in the U.S. matures, mitigating the risk of high-voltage equipment failures becomes an increasingly important issue for transmission owners and operators. Asset owners must anticipate procurement lead times when planning for emergency or unexpected equipment replacements. Certain equipment, such as power transformers, can take up to 18 months from the time of order until installation. This wait can limit the speed of system restoration. Mitigating this requires transmission owners to develop strategies for monitoring their inventory to maintain reliability and control costs.

> Purchasing and positioning spare transformers ahead of time can sharply reduce restoration time if a major transformer fails.

To address these strategic objectives, in 2006 PJM developed a probabilistic risk assessment (PRA) model for managing the existing 500/230 kV transformer infrastructure. The model couples transformer data provided by asset owners with data from PJM market analyses. This data helps estimate annual likelihood of failure, potential replacement costs and installation time for each transformer. The market analyses provide the expected congestion costs associated with the loss of each transformer. The PRA model combines failure likelihood and congestion information to determine the annual risk, in dollars, to the system for the loss of a transformer. The PJM PRA is performed biennially to minimize transformer fleet risk exposure.

PRA Results

PJM's 2006 assessment found 188 500/230 kV transformers in service and 29 dedicated spares. At the time, more than 50 percent of the 188 transformers were more than 30 years old. PJM's PRA analysis identified the need for seven new spares to be located strategically at six substations, and which needed to be able to be moved to other locations as required.

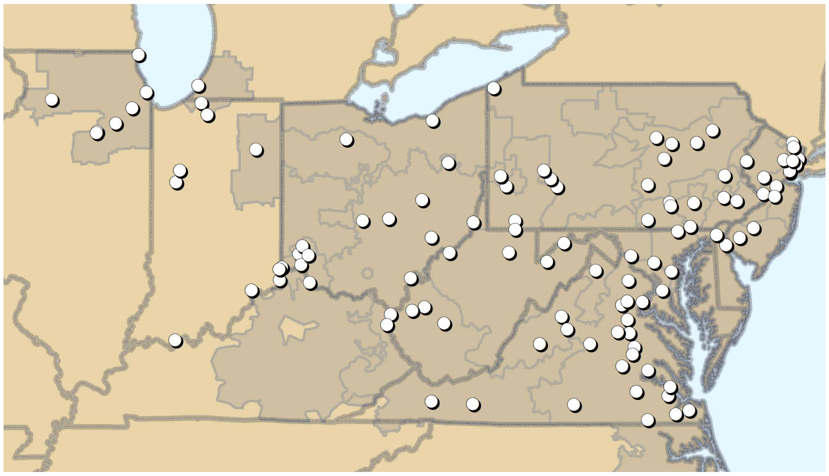
In 2006, these were approved by the PJM Board and were formally included in PJM's RTEP to enhance system reliability and mitigate congestion costs in the event of a transformer failure. PRA analysis identified a congestion risk exposure of $74 million annually that would be mitigated by the deployment of those spare transformers. The PRA also revealed that spares would increase the acceptable risk limit for transformer units in operation, extending their service lives.

System planners and asset owners gain invaluable insight from this process. Knowing and understanding risk has better prepared PJM and its members to proactively and economically address aging transformer infrastructure. Additional analysis has allowed stakeholders to plan proactive transformer replacements, transformer spare purchases and optimal location of spares.

Benefits by the Numbers: Deployment of Phasor Measurement Units

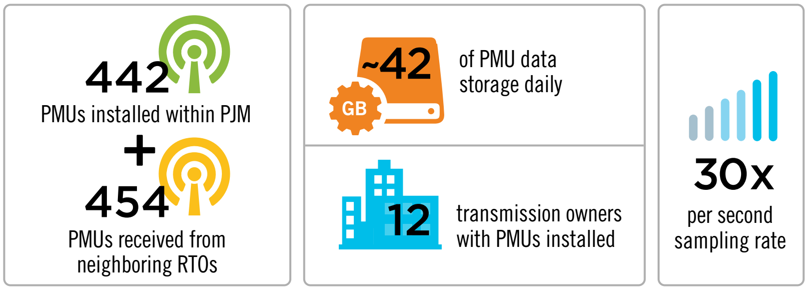
With the aid of a $14 million U.S. Department of Energy stimulus grant, PJM and its member transmission owners have installed more than 400 phasor measurement units (PMUs) in more than 120 substations in 10 states, shown on **Map 13**. PMUs – shown conceptually in **Figure 40** – provide data at a higher resolution and much higher reporting frequency than traditional SCADA (supervisory control and data acquisition) systems, painting a more detailed picture of the status of the grid at any given moment. PJM is developing advanced applications of this technology to improve the efficiency, reliability and resilience of the power system.

Map 13: Location of Phasor Measurement Units Across PJM



> Investment in phasor measurement units across the system help operators detect and address instability before it causes service interruptions.

Figure 40: Using Phasor Measurement Units in PJM



Model validation is a key and novel application of PMUs. Planning, operations and markets rely heavily on models; ensuring that these models accurately represent the physical behavior of the system is critical. PJM is researching other applications, including disturbance detection and location, geomagnetic disturbance monitoring and wide-area controls. In particular, this technology allows PJM to recognize, detect and mitigate electromechanical oscillations, which helps system operators quickly identify potential instability before it has a chance to spread and interrupt service. Overall, further penetration of PMUs promises to revolutionize the practice of evaluating the status of the transmission system, making the process faster and the system more resilient.

Cascading Event Analysis Tool

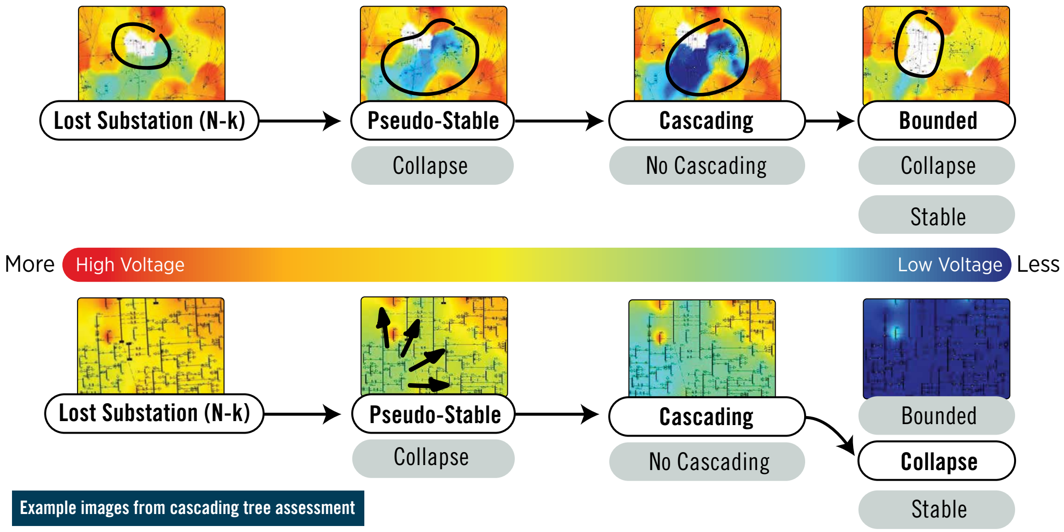
At its most fundamental, a cascading tree evaluates an extreme event that encompasses a risk that may, after some number of additional cascading events, lead to system collapse (i.e., blackout). Major blackouts are usually caused by low-probability, high-consequence events. Since the attacks of 9/11, the power industry has taken a closer look at system contingencies not only driven by naturally occurring events but additional man-made threats as well, including:

- Cyber-attack
- Loss of interdependent systems
- Earthquake
- Physical attack
- Severe terrestrial weather
- Geomagnetic disturbance
- Electromagnetic pulse

Any such initial precipitating event could cause one or more transmission line overloads (on common right-of-way), transformer overload, loss of substation, generator under-voltage, or load under-voltage conditions, among others.

The high-voltage transmission network that crisscrosses the country was planned based on a set of reliability and efficiency criteria. These criteria generally ensure that the transmission system is capable of withstanding a significant outage to one, or a few, critical pieces of equipment. However, these planning criteria do not assess what would happen to the system should a significant disruption of many pieces of equipment occur at once, or in quick succession, as might be triggered by an extreme weather event or a deliberate attack. PJM and transmission owner Dominion Virginia Power have begun developing such an assessment, called "cascading trees," shown conceptually in **Figure 41.** The purpose of this new methodology is to assess the probability and consequence of cascading outages in electric systems. A cascading tree is the set of all likely cascading paths; these, in turn, describe a sequence of potential cascading outages that could reasonably be expected.

Figure 41: Cascading Tree Concept



These possible outages are then classified as shown in **Figure 41** based on whether the propagation of a disturbance can be confined to a certain area or if the exact extent of the cascading cannot be determined. The initial N-k event equates to the complete loss of a substation. Cascading trees quantify the probability of cascading and the extent of associated consequence, leading to a natural ranking of substations. Substations then can be grouped into different tiers, each having a different priority and a discrete set of mitigation actions. Dominion Virginia Power has used this methodology to identify and rank critical substations. The best way to protect a critical substation is to not have one. PJM is currently developing a metric of resilience to complement and enhance a planning process that traditionally has been focused on reliability and efficiency. The intent is to incorporate cascading trees as a weighting factor in the metric of resilience.

Deploying New Transmission Asset Technology

The last five years have brought substantial modernization to system infrastructure. Enhancement of existing equipment, coupled with the application of new tools, has increased efficiency of the equipment and of system operation. Technologies like these are providing PJM with additional tools and operating flexibility to ensure reliability at the lowest cost.

Flexible AC Transmission Systems

A Flexible AC Transmission System (FACTS) is a power system device that takes more conventional power system components – capacitors and reactors – and integrates them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage sourced converter (VSC) technology. By doing so, FACTS devices can directly support additional transmission line power flow with reactive power injections at their point-of-interconnection and can indirectly control power flow by modulating transmission line impedances. The most common FACTS devices include static VAR compensators (SVCs) and Static Compensators (STATCOMs). FACTS device technology was developed as a result of key Electric Power Research Institute research conducted since the 1980s and has been deployed in PJM to help regulate voltage power factor, harmonics and system stability.

> Flexible AC Transmission System (FACTS) technology – developed as a result of key EPRI research since the 1980s – has been deployed in PJM to help regulate voltage, power factor, harmonics and system stability.

SVC devices totaling 5,360 MVAR have been deployed in PJM as RTEP projects since 2013, as discussed in **Section 4**. These devices provide system operators with additional operational flexibility to control voltages, particularly during high-voltage conditions overnight when transmission lines are lightly loaded.

Additionally, PJM TOs have installed 525 MVAR of STATCOM technology with another 125 MVAR planned. A STATCOM includes a unique design that incorporates voltage-sourced converters and thyristor valves to yield additional performance, in terms of speed and dynamic range, as compared to SVC devices.

Transmission Tower Configuration Technology

Transmission towers continue to advance technologically. For example, AEP's Sorenson-Robison Park 345 kV/138 kV line – energized in November 2016 – employs a new tubular steel tower configuration that has yielded shorter tower heights and increased capacity within an existing 138 kV right-of-way. This design, coupled with low-impedance bundled conductors, reduces line losses and significantly increases power delivery capability while avoiding the complexities and costs of series compensation. Overall, the design increases line capacity by 50 percent, reduces system losses and maximizes transmission efficiency. Similarly, lines made from composite-core conductors can lower line losses by 25 percent to 40 percent compared to traditional aluminum-conductor steel-reinforced cable. PJM expects that it will continue to see more transmission tower technology innovations in the future.

Energy Storage

FERC, in an order dated January 21, 2010, addressed the classification of energy storage devices on a case-by-case basis. In the same order, FERC ruled that given certain specific criteria being met, storage devices could be treated as transmission facilities and therefore be compensated in the same way as other transmission facilities.

Energy storage units continue to grow in PJM. Efficient grid operations in an era of rapid growth of renewable energy resources will require increased electric system flexibility. PJM's interest in energy storage of all forms reflects this notion. Energy storage helps grid operators keep the power supply stable when wind, solar or other resources are changing their output due to weather conditions or are simply unavailable. It can also improve the efficiency of the transmission system by increasing the utilization factor of existing transmission and distribution networks, as well as existing generation sources. PJM has worked with various companies and national laboratories to advance the use of energy storage and ensure that the PJM wholesale market is capable of allowing all forms of energy storage to participate and compete in the market.

Today, approximately 5,000 MW of pumped storage hydro, 300 MW of battery and flywheel energy storage, and 70 MW of thermal energy storage are qualified to participate in the PJM markets. This includes everything from large central station generation plants connected at transmission to small kilowatt-level behind-the-meter applications. PJM's new services queue includes energy storage capacity totaling 818 MW as of December 31, 2018, which PJM continues to evaluate.

In March 2018, FERC issued a new regulation, Order No. 841, mandating that all ISOs and RTOs create a market-participation model in which energy storage resources can provide all of the market services that they are technically capable of offering. These new rules, which must be implemented by December 2019, are generally seen as a regulatory step that will help enable further growth of energy storage in the U.S.

Unfolding Initiatives

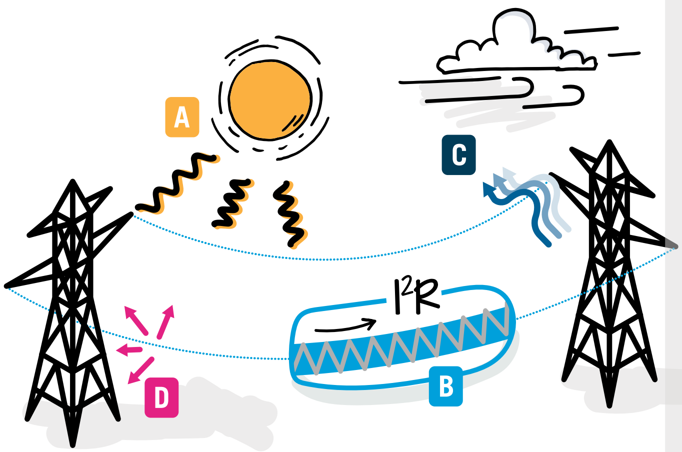
PJM has undertaken a number of initiatives that build on its history of innovation to enhance the reliability and cost-effectiveness of the bulk power system.

Dynamic Line Rating Technology

Dynamic Line Rating (DLR) technology uses advanced sensors and software to monitor real-time conductor temperature along a transmission line. It then uses this data to calculate an actual rating for the line based on environmental conditions, as opposed to modeled scenarios. DLR technology can identify additional capacity on transmission lines that could potentially relieve congestion and create economic efficiencies. Such technology also can contribute to system resilience by providing better monitoring of the real-time capabilities of transmission assets. Every transmission line is designed with a de facto rating that traditionally does not change very often and that is used by PJM and TOs in operating the grid. Introducing DLR technology could allow a more dynamic update of transmission line ratings – for example, hourly, daily, monthly or seasonally – that would improve the reliability and economic efficiency of system operations.

Today, DLR technology – conceptually shown in **Figure 42** – is used in only a select number of locations worldwide. PJM has partnered with transmission owner American Electric Power and DLR technology company LineVision to demonstrate the use of this technology and its potential benefits more widely. To better understand the overall impact of DLR technology, PJM undertook a one-year study of a hypothetical installation on one of its most congested lines. The analysis found that use of the technology could reduce system congestion payments by more than $4 million – providing a rapid, two-month payback of the estimated $500,000 installation cost.

Figure 42: Illustration of DLR



A **Solar heating –** Just as the sun warms the air and the Earth's surface, heat from the sun's rays will raise the temperature at the conductor's surface.

B **Resistive heating –** As current passes through the conductor, heat is generated inside the conductor by electrical losses.

C **Convective cooling –** Nearby wind carries away warm air surrounding the conductor and can cause a dramatic cooling effect along the transmission line.

D **Radiative Cooling –** Even with no wind, transmission lines lose a portion of their heat to cooler ambient air.

Electric Vehicles

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of electric vehicles (EV) on transmission system needs. EEI estimates that EVs will grow from 1 million today to 7 million across the country by 2025.[30] The report goes on to cite the Northeast as one of the regions of the country "… with higher concentrations of first adopters of electric vehicles and more immediate, more ambitious policy targets."[31]

EVs would operate essentially in two modes, potentially based on economic signals sent by PJM:

- Charge on-board batteries from electricity purchased from PJM's Energy Market at distributed charging stations
- Discharge power to the grid to earn revenue in PJM markets for energy and related ancillary services, similar to a generation asset

In either mode, PJM must ensure that transmission capability is in place to accommodate the additional flow of power to charging stations, expected to be highly distributed across local and interstate highway systems. The timing of the coincident effect of EVs' charging cycles could also drive the need for additional generating resources and related transmission, particularly during peak load. This transmission need is amplified if the power needed to charge EV batteries is expected to come from wind and natural gas-fired generating resources, often distant from the population centers they serve.

30 "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid": https://wiresgroup.com/new/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf.

31 Ibid.

Initial PJM Experience

Recently, PJM partnered with companies including BMW North America and General Motors OnStar to demonstrate the potential of aggregated fleets of EVs to respond to certain types of grid signals, such as demand response events, LMPs or the real-time generation profile of renewable energy resources. PJM was an integral partner in one of the world's first successful demonstrations of vehicle-to-grid technology at the University of Delaware, which is continuing to demonstrate the potential for electric vehicles to act as mobile storage devices. As part of this pilot demonstration project, electric BMW Minis charged and discharged in response to the PJM frequency regulation signal and earned approximately $100 per month per car for their services. Given that EVs will be a significant part of future transportation systems, PJM looks forward to playing a role in powering these vehicles and enabling their ability to interact with the grid in innovative ways to maintain reliable and cost-efficient electricity.

Microgrids

Microgrids encompass a combination of increasingly cost-effective distributed generation, environmental motivations and increasing value of highly resilient electric power supply. They are small clusters of energy assets and loads that are controlled to achieve a variety of benefits for the owner/operator. One of the primary benefits of building a microgrid is the ability to provide reliable electric power during significant electric grid disturbances, such as storm outages. PJM works with industry partners, universities and states to better understand how microgrids can impact the grid in a positive way and how they can derive value from the PJM wholesale markets. One such initiative is in PJM's backyard at the Philadelphia Navy Yard, where the Philadelphia Industrial Development Corporation, GE Grid Solutions, The Pennsylvania State University and other partners have created a Microgrid Center of Excellence. The center is demonstrating microgrid control technology coupled with distributed energy assets to improve grid resilience, security, reliability and efficiency, while also incorporating the use of on-site renewable energy.

Distributed Energy Resources

Distributed energy resources continue to introduce another dynamic into PJM's planning process. They can remain on the customer's side of the meter or participate in PJM markets. Distributed energy resources seeking to participate in PJM's wholesale capacity market must do so via PJM's RTEP new services queue process. This ensures that necessary transmission improvements are in place to preserve reliability and that market participation contracts are executed. Distributed energy devices like rooftop solar remain behind the meter and do not participate in PJM capacity markets. Nonetheless, they impact the demand side of PJM resource adequacy. Distributed solar generation acts to offset load, making it lower than it otherwise would be.

Geomagnetic Disturbances

Geomagnetic disturbances, also referred to as solar magnetic disturbances, have the potential to affect the high-voltage transmission system and are of concern to the electricity industry and the government. PJM, which has experienced the impact of such intensified solar activity, has developed specific operating procedures to implement when solar activity is high and could threaten the reliability of the transmission system. Sunspots and other solar phenomena can produce large clouds of plasma (called coronal mass ejections) that can induce electric currents in the Earth and on high-voltage transmission lines. These currents can flow up from the Earth or down into the Earth through grounded grid equipment, mainly transformers. High levels of these ground-induced currents can cause increased reactive power consumption, harmonic currents and hot-spot heating of transformers, the combination of which could result in voltage collapse and blackout.

FERC issued Order No. 779 in 2013 directing NERC to develop reliability standards to address the potential impact of geomagnetic disturbances on reliable system operation. Subsequently, NERC developed reliability standard EOP-010-1 – Geomagnetic Disturbance Operations[32] – and more recently standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.[33] The intent of these standards is to mitigate the risk of instability, uncontrolled separation and cascading outages caused by geomagnetic disturbances. FERC issued Order No. 830 in 2016, approving standard TPL-007-1, including a multi-year implementation plan.

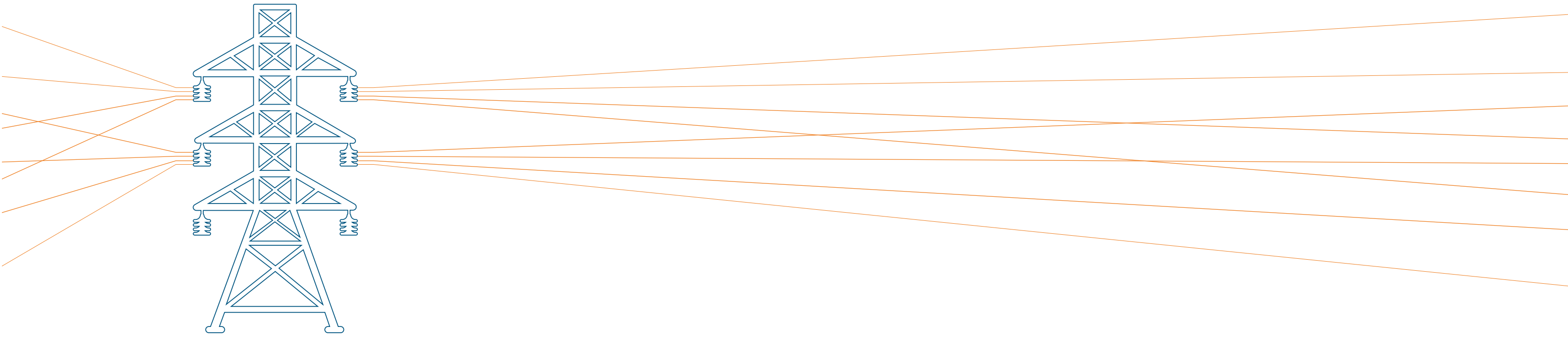
Ocean-Based Wind-Powered Generation

The area off the U.S. Atlantic Coast encompasses a major wind-energy resource that holds the potential to yield thousands of megawatts of power. Efficiently harnessing that energy through the construction of offshore wind farms will require the development of robust transmission to carry the electricity ashore and deliver it to users, particular load centers along the East Coast. Transmission developers are interested in building merchant, non-controllable transmission facilities, AC facilities that eventually will interconnect with future offshore wind-powered generation. Proposed merchant transmission facilities may consist of a single offshore generator lead line or networked offshore transmission facilities. Controllable AC technology, by comparison, allows for the control of the actual amount of power allowed to flow over transmission lines, in particular to other control areas like that between northern New Jersey and New York.

These transmission developers are interested in obtaining capacity interconnection rights to ensure PJM can identify the necessary network upgrades in support of the future generation. This additional process flexibility is expected to accommodate additional wind-powered facilities to participate in PJM's energy and capacity markets. As discussed earlier in **Section 3**, generation powered by renewable fuels like wind provide significant environmental and health benefits.

32 https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-010-1.pdf.

33 https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-1&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States.



Conclusion

The benefits of the transmission system itself and the dollars invested in it extend well beyond delivering power over high-voltage transmission lines. The transmission system ensures reliability, keeps costs low and supports public policy initiatives in the states and federally.

Recent reports indicate that the importance and the need for transmission will grow very quickly over the next 10 years. For instance, one report estimates that rapid electrification of industries that were previously powered by fossil fuels will require transmission investment of $30 to $90 billion by 2030.[34]

As the need for this vital infrastructure grows and changes, PJM will continue to play its role to meet those needs: Planning for the future of the grid to keep power flowing wherever and whenever it's needed.

34 The Brattle Group, "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid." March 2019. https://www.brattle.com/11754