The Price of Peaks: Exploring Shifting Load and Cost in PJM

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ABSTRACT

While some regions continue to experience their highest electrical requirement, or peak load, during the summer, other regions have begun to experience this annual peak in either summer or winter. System peak hours are changing due to shifts in customer loads from technology adoption and new markets including heating electrification, electric vehicle charging, behind the meter solar, and new large loads like data centers.

This paper seeks to better understand the potential for shifts in electrical peaks resulting from these technologies. It will also explore the implications for changing system load profiles for the recovery mechanisms that use peaks to allocate costs. The study will focus on an assessment of system and zonal loads within PJM Interconnection, establishing scenarios for how the highest load hour could shift and, in some cases, cause future peaks in winter. From those scenarios, the potential for changes in how costs are allocated to residential versus non-residential customers are assessed and summarized.

Introduction

The United States is entering a period of unprecedented change to its electricity grid. Global initiatives from the World Climate Conference [1979], the International Governmental Panel on Climate Change [1988], and the Kyoto Protocol [1997] have called for action to eliminate GHG emissions. Recently, the current U.S administration has reversed position on previous initiatives including the Paris Agreement and funds for climate incentives from the Inflation Reduction Act. Despite this, states, cities and businesses still pursue climate goals and technological solutions, like electrification of heating and transportation, to transition away from fossil fuel energy sources. These solutions, whether pursued through customer choice or policy, will require expanded grid capabilities and investment.

Concurrently, accelerated integration of data centers is increasing current and planned electrical loads. Their addition will require management of the multi-state high voltage electric grid by the regional transmission organizations (RTOs) that oversee them. Customer loads are also shifting due to the growth in the installation of solar panels and increased loads, including electric vehicle charging. Together, these and other factors are creating fundamental changes in the location, the amount, and time dependence of societies' electricity needs.

This paper explores some of the outcomes resulting from these changes by focusing on four scenarios: scaled integration of residential heat pumps, residential solar, residential EV charging, and data centers. These limited scenarios are not meant to serve to predict future outcomes, but rather to provide insight into the potential impacts of these four technologies on both system load and cost shifting between residential customers and other rate classes.

Before exploring the scenarios themselves, it is important to establish an understanding of the importance of both increased peak loads, and the potential changes to the electrical load shape itself. Increased electricity transmission, whether to support increased customer loads or carry power from distributed behind the meter generation, will require increased infrastructure investment in lines, transformers, and equipment by electric utilities. Utilities will recover the cost of these investments from customers through their electricity rates. In Ohio, electricity costs are comprised of four categories of investment and operation:

- **Generation costs** pay for the power plants that generate the electricity used by customers who are billed by the distribution utility or supplier depending upon who customers receive power from.
- **Transmission costs** pay for the high voltage grid transferring power from generators to the distribution utilities. The transmission utility recovers these costs from each distribution utility in their territory, who in turn use rates to recover these funds from customers.
- **Distribution costs** pay for the low voltage grid transferring power from the transmission system to customers. Distribution utilities recover these costs using rates approved by the utility commission within their state of operation.
- **PJM Reliability costs** pay to ensure there is sufficient generation capacity available during the highest hours of electrical load within the RTO system. These costs are determined using PJM's Reliability Pricing Model Base Residual Auction, often referred to as the capacity auction. They are then recovered from each distribution utility in their territory, who in turn use rates to recover these funds from customers.

In PJM, the RTO for Ohio, transmission and RTO reliability charges are recovered based upon a distribution utility's electric load during the highest load hours of the transmission and RTO systems respectively. This study will explore how the proportional contribution of residential customers during these peaks, and thus the costs recovered, could shift with technology adoption using these scenarios explored within PJM.

Background and Recent History in PJM

PJM is an RTO for an area made up of 21 transmission zones across 13 states and the District of Columbia. Serving more than 67 million people, PJM oversees the transmission system and dispatches the generation for this region to ensure it is reliable and safe. A map of PJM is seen in Figure 1.

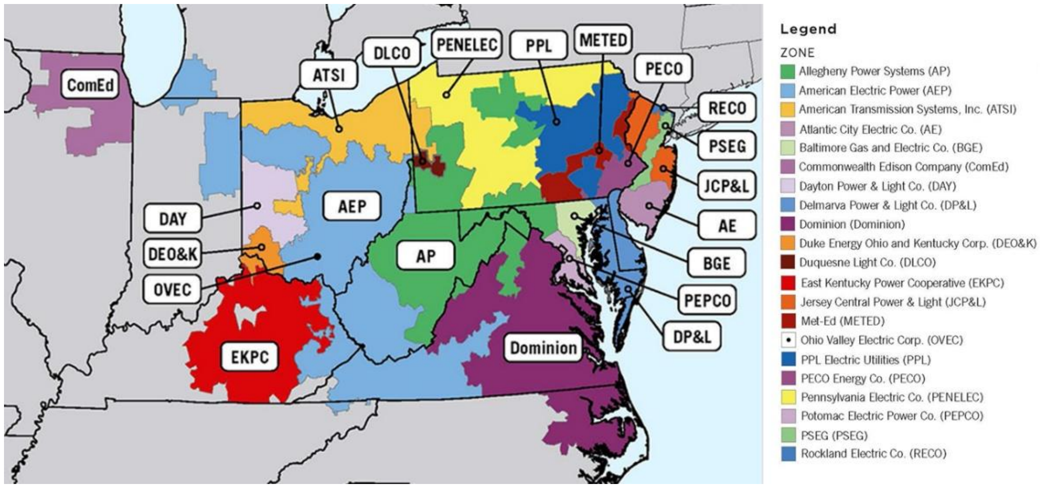

Figure 1. Map of PJM territory and transmission zones. *Source*: PJMa 2026

Cost Recovery for RTO Reliability and Transmission in PJM

Within PJM, two electricity price components are allocated based upon system load peaks. These are the RTO reliability, which is established through PJM's capacity auction, and transmission costs. To understand their allocation, it is helpful to first understand the peak definitions used to assess these costs. Coincident peak (CP) refers to the highest daily load experienced within a system and is defined based upon the instances. When the single highest daily load hour is used, it is referred to as the 1CP. When the five highest daily load hours are used, it is referred to as the 5CP. It follows that there are many combinations of maximum daily loads that can be used in assessing contribution to a system's electrical peak hour.

To analyze peaking trends amongst PJM's RTO, transmission zones, and distribution utilities, data was obtained from a variety of sources. This included:

- PJM filings of historical data on system performance. (PJMb 2026)
- Data from PJM's enhanced data management tool Data Miner 2 (DM2) including hourly load data for both the RTO and transmission zones. (PJMc 2026)
- Hourly average temperature data from weather files obtained from Iowa State University's Mesonet for weather stations central to analyzed transmission zones. (IEM 2026)
- Publicly available information on investor-owned utilities in Ohio, specifically residential hourly load data from the auctions used to contract generation contracts.

In PJM, reliability costs are set through its capacity auction and are assessed using a 5CP referred to as the Peak Load Contribution (PLC). The PLC is an average of the five highest daily load hours for a customer during PJM's summer period. Within PJM, summer and winter periods are defined in Manual 19 and 18 respectively, with summer between June 1st and September 30th and winter between November 1st and April 30th. To compare winter and summer peaks, metered load records were obtained from DM2 (PJMc 2026). Figure 2 shows historical trends of summer and winter 1CPs from 2007 to 2025.

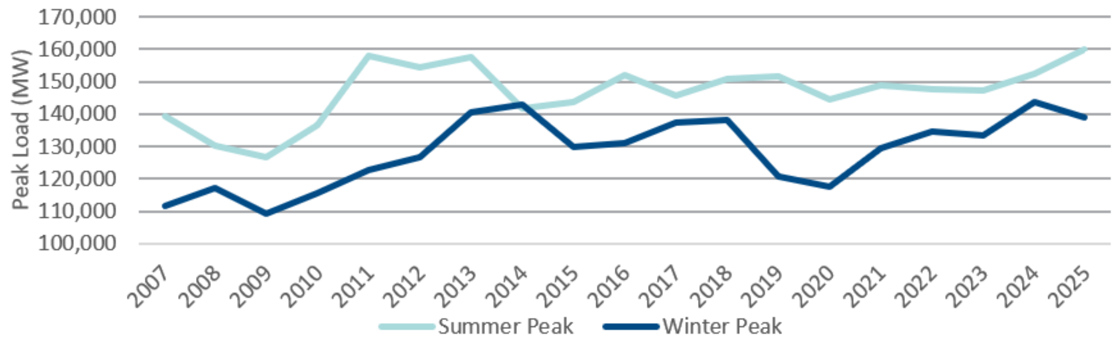

Figure 2. Historical trends of PJM summer and winter 1CP. *Source*: PJMc 2026

Historically, the highest summer peaks are greater than the largest winter peaks, with the summer peak being 14% larger than the winter peak on average. For grid forecasting purposes, this illuminates why potential summer loads in PJM are the basis for generation resource planning.

Figure 3 shows zonal contributions to the PJM 1CP for both summer and winter using data from DM2 for consecutive seasons. This illustrates the zones with the greatest contributors to peaks and the difference between peaks in summer and winter in each zone. The AEP, DOM, and CE zones are the largest contributors to peaks. Within this comparison, AEP and DOM have slightly larger winter peaks, while CE (ComEd) has a much lower load during winter compared to summer. The seasonal difference in PJM's peaks is the cumulative differences within each transmission zone. It follows that if enough transmission zones see larger winter peaks than summer, the entire RTO system could begin experiencing its largest load hour during the winter.

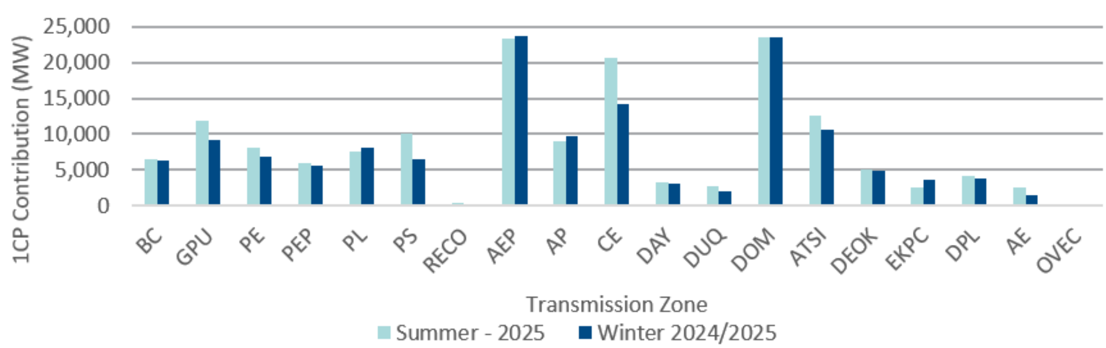

Figure 3. Historical summer and winter 1CP by PJM transmission zone. *Source*: PJMc 2026

Within Ohio PJM transmission zones, costs are allocated to distribution utilities using a 1CP called the Network Service Peak Load (NSPL). NSPL is set annually from November through October of the following year and is set independently within each zone as the highest load hour experienced. Transmission zone NSPL hours can differ between zones and the PLC. Fifteen years of historical NSPL data was collected for the twenty-one transmission zones within

PJM from annual reports. NSPL hours were categorized as summer[1], or winter[2] peaks based on their date. Analysis shows more than half of the zones have experienced a winter NSPL in that period. Figure 4 shows a trend of the frequency of winter NSPLs over time starting in 2015.

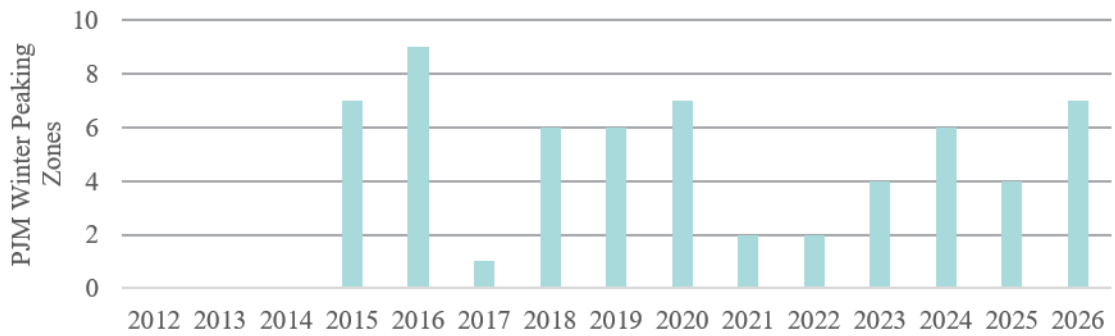

Figure 4. Frequency of winter peaking within PJM transmission zones. *Source*: PJMc 2026

In Ohio, there are four transmission zones, three of which include regions outside of the state. Each transmission zone is comprised of a mix of investor-owned, municipal, and cooperative utilities. The AEP transmission zone includes subregions in Ohio (AEPOPT), West Virginia and Virginia (AEPAPT), Kentucky (AEPKPT), and Indiana and Michigan (AEPIMP). Collectively, the AEP transmission zone's NSPL occurs in winter roughly 50% of the time.

Influence of Weather

Within AEP's transmission zone, winter peaks exceed summer peaks in the predominantly Appalachian regions, AEPAPT and AEPKPT. Electrical heating loads are often identified as a contributor because rural customers with limited natural gas access use higher rates of electric heating. High performance heat pump adoption will minimize the load increase for some of these rural customers during the coldest winter hours, but in many cases, customers will use heat pumps with poor low-ambient performance and will still be reliant on electric resistance back-up heat during these peak hours.

Figure 5 shows AEP transmission zone's hourly load versus regional temperature. These trends display the increased usage required at higher temperatures for cooling and lower temperatures for heating. The highest loads in the Appalachian zones occur in colder hours. It is important to note that the adoption of electrical heating via heat pumps will increase cold weather usage, which over time is likely to result in winter peaking in regions with heating dominated climates.

[1] July through September
[2] November through March

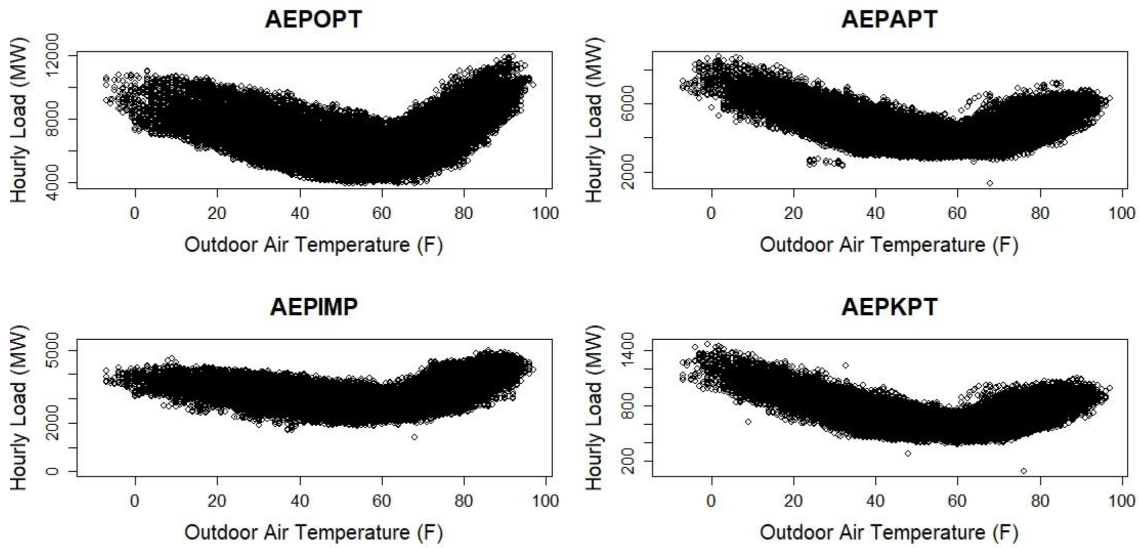

Figure 5. AEP transmission zones' hourly load versus temperature. *Source*: PJMc 2026, IEM 2026

Technology Scenarios

Working from this background, an exploration of the four scenarios can begin. For each technology, a theoretical load is applied to historical metered load from DM2 for the portion of each transmission zone serving Ohio. In DM2 these loads correspond to the American Electric Power Service Corporation (AEPOPT), American Transmission Systems, Inc (OE), Duke Energy Ohio & Kentucky (DEOK), and AES Ohio (DAY). Scenarios were selected based upon peak shifting potential, information availability, and presence in existing markets.

The four technologies upon which scenarios are created are behind the meter solar, residential heat pumps, residential EV charging, and large data centers. This limited investigation is not meant to be comprehensive but rather a starting point in understanding system peak impact resulting from their adoption. The simplified methods apply an adjustment of known historical loads from DM2 to minimize the factors required for full system models. For scenarios assessing residential technology applications, adoption rates were assumed for 2035 based upon percent growth required to achieve net-zero GHG emissions by 2050 (State and EOP 2021) from estimates for adoption rates in 2024. While imperfect, residential customer counts are extrapolated using data on Standard Service Offer (SSO) auction websites for Ohio's investor-owned utilities. For heat pump and solar analysis, historical weather central to the zone is used (IEM 2026), Cleveland for OE, Columbus for AEPOPT, Cincinnati for DEOK, and Dayton for DAY. To illustrate methods, results for the AEPOPT daily trends for peak days will be presented in figures. To illustrate systems in 2024, Figure 6 shows the day of year and hour of the top 18 daily peaks in each zone. This shows these peaks occurring during summer in the afternoon.

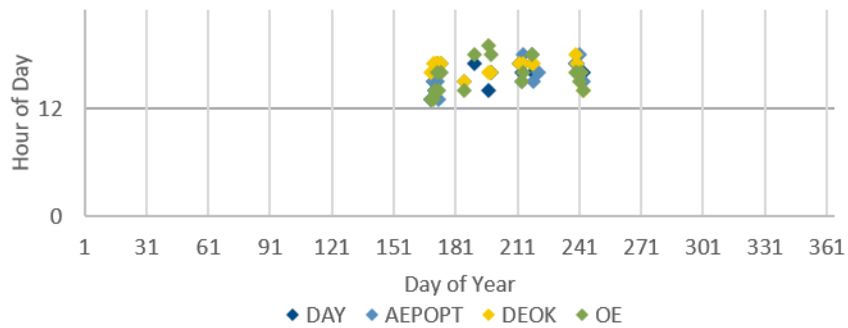

Figure 6. Top 18 zonal daily peaks by day and hour.

Heat Pumps

Electrification of residential space heating requires replacing existing combustion-based heating equipment with electric alternatives, which for this study are air source heat pumps (ASHP). BEopt software (version 3.0.1.0) was used to simulate a typical temperature-dependent residential heating load in PJM with characteristics representing the average existing residential building stock, using values where applicable. Assumptions include a square footage of 2,184 ft^2 (EIAb 2020), unfinished basement, two stories, R-7 wall and R-13 attic insulation, 15% window wall area of R-0.49 double pane windows, and heating and cooling setpoints of 68° and 76° F respectively. Typical meteorological data (TMY3) for Columbus, Ohio is also used. Figure 7 shows the regression line fit for heating load based on temperature for an average house.

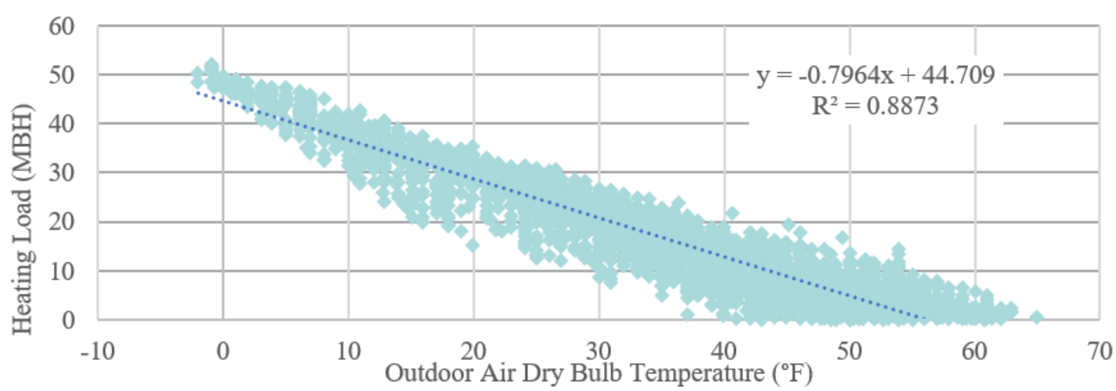

Figure 7. BEopt model output – average home heating load vs. temperature.

To convert this heating load to electric requirement, typical heat pump performance was modeled using available manufacturer data for standard (SEM) and high efficiency cold-climate models (HEM). Assuming adoption of 70% HEM and 30% SEM, a combined performance curve was generated, seen in Figure 8. ASHP units were sized to operate without electric resistance auxiliary heat down to 10°F and 20°F for the cold climate and standard models respectively. This illustrates how ASHP performance is reduced as outdoor air temperature is colder.

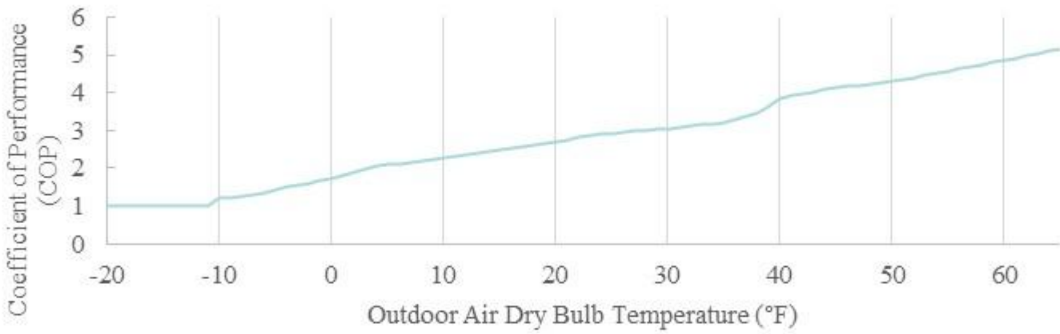

Figure 8. Combined ASHP COP Performance vs Temperature

Electric resistance is used in 34% of electrically heated homes in the East North Central[3] region (EIA, RECS 2020). Assuming an equipment life of 15 years, electric resistance units are assumed to be replaced with more efficiency ASHP alternatives at a rate of 6.7%. This analysis incorporates this performance improvement across the entire heating equipment population.

For the East North Central region, 9% of residences have electrical heating (EIA, RECS 2020). This means to achieve 2050 goals, an additional 39% of residences will need to install ASHPs, increasing system load in the coldest hours. Figure 9 shows the day of year and hour of the top 18 daily peaks in each zone for this scenario. This shows peaks shifting to winter months at earlier and later hours than the baseline presented in Figure 6.

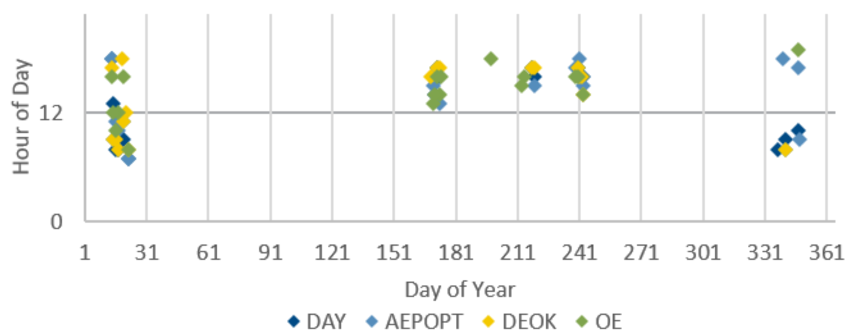

Figure 9. Top 18 zonal daily peaks by day and hour for heat pump scenario.

Residential Behind the Meter Solar

Reaching GHG goals will also require decarbonization of electricity sources. Behind the meter generation can accomplish this by reducing system load near the end use. An hourly solar generation profile was generated for a 1kW solar system modeled in PVWatts (NLRa 2024) for each zone's primary city. Models assume a south-facing system with a tilt of 20°. PVWatts output is based on typical weather (TMY3) weather files. It is used to establish the relationship

[3] Ohio is located within this region.

between global horizontal irradiance (GHI) and system output for each region, that is used to extrapolate solar generation using actual GHI from National Laboratory of the Rockies' National Solar Radiation Database (NSRD) (NLRb 2024). This facilitates a rough estimate solar production within each zone. Average system size is assumed to be 7kW based upon a study from Lawrence Berkeley National Laboratory (Barbosa 2022).

The Department of Energy (DOE) reports that 3% of residential customers have solar (DOE 2024). This means to achieve 2050 goals, an additional 41% of residences will need to install solar. The addition of solar reduces residential end use during daylight hours, with greater generation during the summer. Figure 10 shows the day of year and hour of the top 18 daily peaks in each zone for this scenario. When compared to Figure 6, this shows that the reduced loads during midday manifest in peak shifts to later hours during summer and some winter peaks ranked in the top 5% of annual hours.

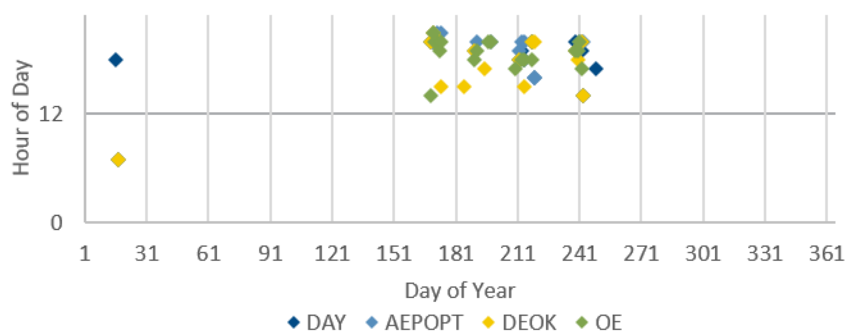

Figure 10. Top 18 zonal daily peaks by day and hour for residential solar scenario.

EV Charging

Shifting to renewable transportation is another important piece of decarbonization. Scenario modeling is based upon annual average hourly charging profiles for Plug-In Electric Vehicles (PEV) from an NREL Study of both level 1 and level 2 chargers (Speake 2025) that are presented in Figure 11. The study finds that on average PEV owners will continue to plug in vehicles upon arrival home after daily travel beginning in early evening.

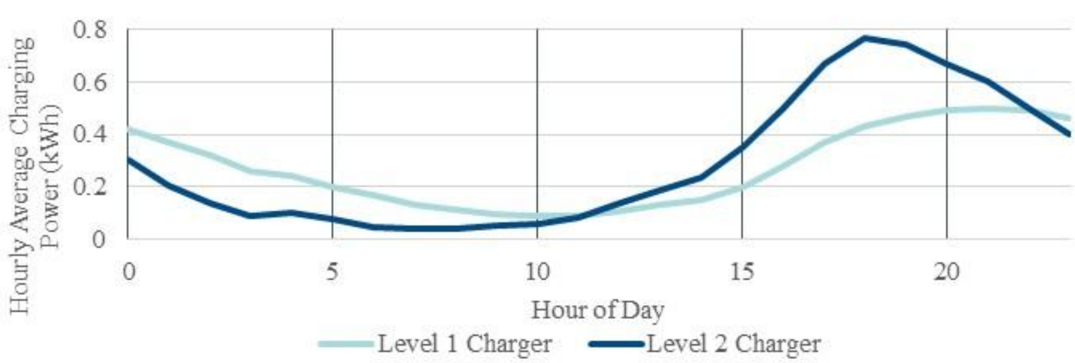

Figure 11. National Average Charging Energy Consumption Profile. *Source*: Speake 2025.

A study of registered vehicles in Ohio indicates 1% are plug-in and can utilize charging (ODOT, DriveOhio 2026). This means to achieve 2050 goals, an additional 42% of residences could add charging to support vehicle fueling. The addition of electric vehicles increased grid load in afternoons and evenings. Figure 12 shows the day of year and hour of the top 18 daily peaks in each zone for this scenario. When compared to Figure 6, this shows that while peaks still occur in summer, they occur in later hours. It is worth noting that due to the lower magnitude of the modeled load applied, this scenario's impact is the lowest of those explored.

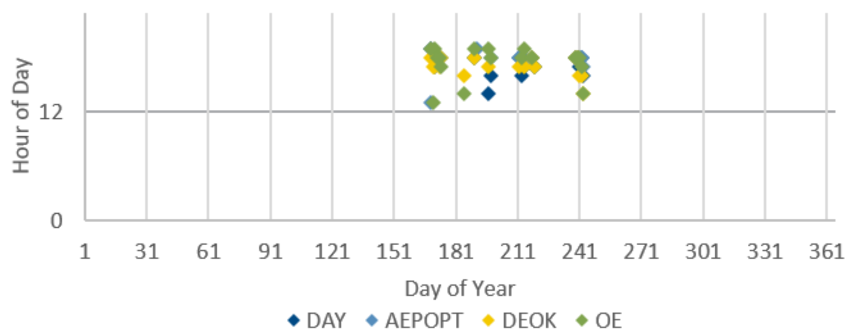

Figure 12. Top 18 zonal daily peaks by day and hour for EV charging.

Data Centers

Data centers are perhaps the most disruptive new load to be added to the grid, specifically hyperscale facilities, given their incredible size and the speed with which they are being added. Within this scenario data centers are modeled as a constant system load increase that does not vary demand for seasonal temperatures or operational modes. Understanding load growth from data centers is challenging as utilities continually revise the forecasts as more potential customers request utility connections. These timelines are further confounded given both the size of these new customers and the sheer scale of generation and transmission infrastructure that will be needed to support them. It has led to an evolving landscape within the FERC rules, RTO level transmission rules, state level distribution rate cases, and reliability planning.

For this scenario, the capacity added for data centers is based upon PJM's 2026 load forecasts for each zone through 2035 (PJMd). Applying these PJM forecasts equally within each zone, they project increases of 7,000 MW (64%) in AEPOPT, 2,500 MW (75%) in DAY, 500 MW (5%) in DEOK, and 2,500 (24%) in OE. Debate on the certainty of load forecasts continues, with uncertainty on the load that will materialize, and when. One survey found that 35% (EPRI 2024) of forecasted load was likely to be installed. Despite this, data center development continues to accelerate in PJM planning, with some projects exceeding 1GW. Based on these assumptions, the date and time of current peaks remain constant but at much larger magnitudes. Traditional curtailment for facilities of this magnitude, reducing load for short periods for peak shaving cost savings, seem likely to merely shift coincident peaks to an alternative hour when they operate at maximum load. This new hour would also be when the rest of the system's load is lower, offering no incentive for such pursuits. The conclusion is that, based upon this scenario, data centers would not shift currently identified peaks, even when considering short term peak avoidance strategies like curtailment. As clearer understandings of the actual load profiles of these facilities are gained, any variability in seasonal or hourly operations could impact when peaks occur.

Economics Implications

The recovery mechanism for two of the electrical grid costs, reliability and transmission, depend on peak load hours. They are the 5CP PLC and 1CP NSPL respectively. Ohio utilities use proportional contributions during peaks to allocate these costs to each rate class. This means to estimate cost impacts for residential customers, their proportional contribution to peaks is needed. To estimate this allocation, hourly load data containing the residential contribution for Ohio's investor-owned distribution utilities (IOU) was obtained and overlaid with the 2024 DM2 load data (AEP 2026, AES 2026, Duke 2026, FE 2026). While these records include only IOU customers, it was used to extrapolate the residential proportion of the transmission zone load in 2024.

The PJM capacity price is the rate applied to PLC peaks for reliability cost recovery and is generated through the PJM capacity auctions. The auctions send a price signal to stimulate new generation construction to meet grid needs. Figure 13 shows capacity price history and the surge occurring in recent years. Residential rates are a function of both this increased price and residential customers' proportion of the PLC.

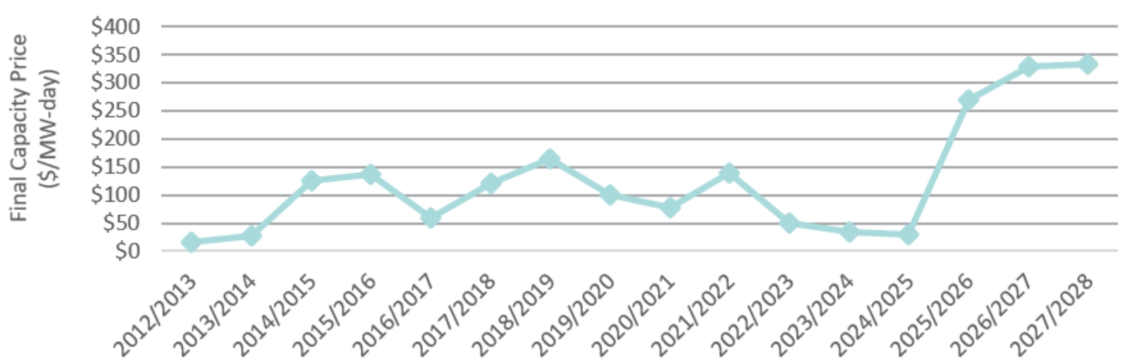

Figure 13. Time trend of PJM Capacity Ohio Transmission Utility Network Service Rate
Source: PJMc 2026

Transmission costs are recovered using the network service rate. The network service rate is the transmission utilities annual revenue requirement divided by the previous periods NSPL. Distribution companies create rates to recover this cost and in Ohio allocation is commonly based upon NSPL. Figure 14 shows the history of the network service rate for each of the transmission zones serving Ohio customers has been increasing annually in recent years.

Figure 14. Time trend of Ohio Transmission Utility Network Service Rate *Source*: PJMc 2026

Increased loads, whether for residential needs or data centers, will require increased investment from the utilities. This buildout has potential to increase or decrease reliability and transmission rates as a function of both the added cost recovery for utility infrastructure and the increased customer contribution to load during peak hours. To focus on the impact of peak shifting for scenarios that result in system load profile changes, it is assumed that capacity and transmission costs remain constant so that the shift in peak contribution can be considered in isolation.

For the first three scenarios, the residential percentage of peak load broken out by scenario and region are presented in Table 1. At a high level, increases can be seen for all three technologies considered when compared to the current peaks. This is both a reflection of the increased load within the customer class that results as well as the difference existing between the previous peaks and the new highest load hours.

Table 1. Median residential customer peak contribution for top 18 by scenarios and region.

Region	Current Peaks	Heat Pump Scenario	Residential Solar Scenario	EV Charging Scenario
AEPOPT	39%	44%	39%	44%
DAY	47%	52%	50%	52%
DEOK	49%	53%	49%	52%
OE	39%	45%	46%	50%
Ohio	41%	44%	45%	49%

Without more detailed information on how data center facilities will be operated, it is assumed their addition will not change when systems' peaks occur. It follows that their addition will not result in a change of residential customer cost allocation as a result. Instead, they could impact residential customer transmission and RTO reliability costs in two critical ways:

- First, they could change the cost per MW of both transmission and RTO reliability. Due to their size, and the significant amount of transmission and RTO reliability investment required to add them to the system, it is critical that data center loads are connected to the grid as cost efficiently as possible. Examples can be found of new data center additions that have resulted in decreased costs per MW, and others have led to increases. One

factor involved is the difference in cost for adding these large loads due to existing head room and proximity to high voltage service, or a lack thereof. A second is the way in which the costs for connecting these customers, and then upgrading the overall system to support them, are either paid directly by the new customer or socialized to all ratepayers.
- Second, it is uncertain how much of the currently forecasted data center loads will ultimately materialize. If only half of the forecasted 7,000 MW additions to the AEP zone manifest into actual power requirements, the transmission and RTO system upgrade costs that have already been incurred will still need to be recovered. This will result in an overbuilt grid that customers will pay for in the form of higher transmission and RTO costs.

Conclusion

This study begins to provide insights into the potential shift in residential costs resulting from changes in when grid peaks occur and the proportion of contribution for that rate class as new technologies proliferate and decarbonization is pursued. The scenarios illuminate that there is some potential for such cost shifts to occur as these technologies are integrated at an accelerated pace. The takeaway should not be to avoid this transition. Rather, it shows a need to better understand how costs may change because of technology shifts in the built environment and from the addition of new large loads like data centers. In better understanding, opportunities can be leveraged to mitigate risk and more effectively evolve existing practices. Some opportunities illuminated from this study include continued:

- Integration of existing energy efficiency technologies to reduce existing load and increase available capacity for new loads without requiring additional infrastructure.
- Improvements in efficiencies of our buildings and equipment, especially for heating and cooling applications, to allow scaled decarbonization while minimizing the additional capacity required to support it.
- Oversight, focus, and engagement to ensure electricity costs are recovered fairly, send effective price signals, and continue to evolve with changing technological capabilities.
- Diligence in implementation and maintenance of residential technologies resulting in optimized operation throughout equipment life.
- Incorporation of electrical storage systems with distributed energy generation, like solar, to allow dispatch of energy to optimize customer and/or system load.
- Exploration of scheduling of scaled technologies, like EV charging, to coordinate their aggregate load for periods of greatest availability of the grid.
- Discussion, transparency, and scrutiny of the still developing processes and oversight for data centers, to ensure their forecasted need is accurate and unnecessary infrastructure buildout is not carried by existing customers.

While not comprehensive, this study exposes potential risk in the attribution of system costs to a single hour, or small number, of hours. Society is entering a period where there is potential for a system’s peak hour to vary widely as end users and markets continue to evolve. Technology is at the same time increasing the capability of customers to change their load shape.

Whether existing rates will need to be revised, or other mechanisms are put in place to fairly allocate costs, is yet to be seen. It is hoped that this initial investigation promotes greater awareness of this possibility and inspires others to consider further investigations into this topic.

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