A recent study by the Lawrence Berkeley National Laboratory (LBNL) analyzed state-level trends across retail electricity prices from 2019-2025 (inclusive of the residential, commercial and industrial sectors).[26,27] Generally, the study also found that states with the highest load growth saw declining average retail prices between 2019-2025, with prices increasing in states experiencing load declines. Specifically, North Dakota, New Mexico, and Nebraska saw substantial commercial and industrial (C&I) load growth but saw lowered residential and C&I prices. However, PJM was the exception to this trend, with data centers found to be one of multiple factors contributing to increasing capacity prices between the 2024/2025 and 2025/2026 auctions (which is further discussed in this paper's PJM Market Overview); the study also notes capacity prices are one but not the only contributor to retail rate price increases.

An E3 study funded by Amazon analyzed data from Amazon data centers across four utility territories (Pacific Gas & Electric in California, Umatilla Electric Cooperative in Oregon, Dominion Energy in Virginia, and Entergy in Mississippi), selected to reflect a diverse range of geographies and market structures.[28] To assess the data centers' impact, the analysis compared each facility's electricity payments (i.e., utility revenue) to the utility's marginal cost to serve the facility.

Across all case studies, Amazon utility payments met or exceeded the incremental cost to serve, producing neutral to positive outcomes for other utility customers, such as downward rate pressure. On average, each facility generated $3.4 million in net surplus (i.e., revenues exceeding costs) that utilities could use to reduce rates for other customers, but implementation may vary by jurisdiction. Results were similar when projecting to 2030 as well, with surplus value of up to $6.1 million per 100 MW data center.[29] This surplus arises because much of a utility's network and public policy costs are fixed; adding large, high-load factor loads like data centers spreads those costs over more usage (i.e., kilowatt-hours), the amount of revenue the utility must collect from other customers and thus reducing their cost burden. Accordingly, the analysis found no evidence of cross-subsidization on an individual data center basis and that the evaluated facilities can actually produce benefits for other customers.

The study does caution that due to pace and scale of this load growth (both on an individual facility basis and in the aggregate) and tightening supply, utilities must keep pace and leverage the full range of risk mitigation tools available to them to continue to prevent cross-subsidization. The paper outlines key tools to consider and provides guidance on selecting among them based on factors such as utility size, market structure, scale of load growth, risk approach, etc.

These factors are critical because how large loads are integrated into the grid determine their impact on retail prices. For example, rates could rise if utilities invest in costly infrastructure to integrate new loads that later fail to materialize or underperform; as discussed in the next section, such risks can be simply and effectively mitigated through rate design and other risk mitigation tools. Conversely, large loads can help reduce rates by spreading fixed costs over their high usage, as illustrated above, and/or by minimizing their impact on the grid, such as by curtailing their demand during periods of grid stress.[30]

Utilities have seen data center growth create downward pressure on electricity rates by improving system utilization and spreading fixed costs across a broader demand base. Xcel Energy CEO Bob Frenzel explains the underlying mechanism: "if you put more units of production through a fixed asset, the rate for everybody comes down. A large data center load on your system should, all things being equal, drive prices down for electricity, not up."[31] In Georgia growth is expected to place downward pressure on residential bills of $8.50/month from 2029-2031, and in Michigan residential costs are expected to lower by 8% due to recently approved data center contracts.[32] In more illustrative terms, the South Carolina Power Team shared that "in 2024, Google paid the equivalent of 136,000 residential homes to our fixed costs. That's 136,000 homes that we'd have to bring into our system to offset what they're bringing to us. If they're not here, those costs are spread amongst all of our members. The economic impact and benefit for our system is just huge."[33] Pacific Gas

[26] Wiser, R., O'Shaughnessy, E., Barbose, G., Cappers, P., & Gorman, W. (2025). *Factors influencing recent trends in retail electricity prices in the United States. The Electricity Journal, 38(4)*, Article 107516. https://doi.org/10.1016/j.tej.2025.107516

[27] Wiser, R. H., Barbose, G. L., Gorman, W., O'Shaughnessy, E., Forrester, S., Donohoo-Vallett, P., Cappers, P., Deason, J., Hledik, R., & Lam, L. (2026). *Retail electricity price trends and drivers: Data update—2026 edition*. Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf

[28] Riu, I., Patel, K., Mettetal, L., Santoni-Colvin, M., Greszczuk, S., Cardona, J., Bertrand, L., Spencer, S., & Ramirez, S. (2025). *Tailored for scale: Designing electric rates and tariffs for large loads*. Energy and Environmental Economics, Inc. https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

[29] The projections evaluated Amazon data centers in isolation, without modeling underlying system changes to supply and demand. For the 2030 projects, current rate constructs were extended to develop bookend scenarios to illustrate the range of impacts under various resource assumptions.

[30] Borenstein, S. (2025, September 29). *What will data centers do to your electric bill?* Energy Institute Blog. https://energyathaas.wordpress.com/2025/09/29/what-will-data-centers-do-to-your-electric-bill/

[31] Bob Frenzel, Chairman & CEO, Xcel Energy, remarks on data center load and electricity pricing, *Finance & Commerce*, 2026. https://finance-commerce.com/2026/01/xcel-energy-ceo-data-centers-lower-electricity-costs/

[32] Wiser, R. H., Barbose, G. L., Gorman, W., O'Shaughnessy, E., Forrester, S., Donohoo-Vallett, P., Cappers, P., Deason, J., Hledik, R., & Lam, L. (2026). *Retail electricity price trends and drivers: Data update—2026 edition*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf

[33] James Chavez, President & CEO, South Carolina Power Team, remarks on Google load contributions and fixed cost recovery, 2025.

& Electric (PG&E) has also found this to be true and measured the benefit, reporting large load growth has enabled electric rate reductions four times over the past two years; it estimates that each gigawatt of new load can lower customer bills by 1%, but wildfire-related costs continue to put pressure on overall affordability.[34]

In examining data centers in the aggregate, E3's study for the Virginia Joint Legislative Audit and Review Commission (JLARC) also found no evidence of a significant historical and present-day cost shift in the state which includes the world's largest data center market. The analysis concluded that Virginia's current retail rate structures appropriately allocate costs to the customer classes responsible for incurring them, with data center customers paying their proportional share of generation, transmission, and distribution costs.[35]

The study emphasizes, however, that maintaining rate equity becomes more complex as load growth accelerates. Because cost allocation factors and revenue requirements are updated periodically through regulatory proceedings, rapid increases in large load demand can create temporary imbalances between cost incurrence and cost recovery. In such cases, regulatory lag may result in short-term under-collection from fast-growing customer classes and over-collection from others until rates are reset. The study further notes that large-scale demand growth is unlikely to place downward pressure on retail rates in the near term without substantial generation and transmission investments made in advance of, or concurrent with, load expansion.

Finally, the analysis identifies additional structural considerations that could influence retail prices even when cost allocation methodologies are conceptually sound. These include the magnitude of required capital investment and its implications for utilities' cost of capital, the potential for stranded costs if large load customers depart under competitive supply arrangements without appropriate indifference mechanisms, and localized wholesale price effects where concentrated load growth increases congestion and locational marginal prices. The overarching conclusion is that current regulatory frameworks are functioning as intended, but sustaining that outcome amid continued rapid data center expansion will require vigilant oversight, timely rate adjustments, and rate design mechanisms that appropriately align cost responsibility with cost causation.

A 2026 Georgia Institute of Technology working paper, *The Local Economic Effects of Data Center Entry*,[36] provides one of the most systematic retrospective analyses of local impacts following data center entry. Using a difference-in-differences approach, the paper estimates that data center entry can raise local electricity rates, although impacts are difficult to isolate because utility service territories often span multiple counties. In counties with lower "spillover exposure"—that is, counties sharing a utility with fewer neighboring counties—the paper finds statistically significant price increases of about 5.0% for total electricity prices; these are driven by larger estimated increases in industrial rates (6.6%) and smaller increases in residential and commercial rates (3.6% each). These results measure near to medium-term effects, comparing prices three years before and after data center activation between 2010-2024. In higher-spillover areas, the estimates are weaker or not statistically significant, which the authors interpret as a measurement problem rather than evidence of no effect. Because prices are measured at the county level while costs are recovered across wider utility territories, the paper may understate the full geographic reach of rate impacts even in cases where it detects statistically significant effects for individual counties, and the authors are careful in stating that the results should be interpreted with caution.

While informative, the study has limitations that are important to note. Its causal design compares counties with and without data center entry, but the authors acknowledge they cannot fully rule out selection bias if data centers are more likely to locate in areas already on stronger growth trajectories. Further, the finding in only low spillover counties points towards relatively small utility territories and the median data center entry is 10 MW, so it is not fully representative of general trends. More broadly, the study focuses on initial data center entry and cannot fully disentangle the effects of later clustering, local selection factors, or other unobserved differences in data center siting and economic outcomes. In addition, the study does not differentiate the effect of recently published utility rates designed to protect ratepayers from rising cost, nor does it evaluate how fairly costs are distributed across customer classes. As such, the findings may best be viewed as an early indication of possible price effects, rather than a definitive estimate, highlighting the need for further research, particularly in understanding the effects of today's rapidly expanding large load clusters.

[34] Penrod, E. (2026, February 17). *Data center growth has helped PG&E cut rates 11% since 2024, CEO says.* Utility Dive. https://www.utilitydive.com/news/data-center-growth-has-helped-pge-cut-rates-11-since-2024-ceo-says/812230/

[35] Patel, K., Steinberger, K., DeBenedictis, A., Wu, M., Blair, J., Picciano, P., Oporto, P., Li, R., Mahoney, B., Solfest, A., Bhandarkar, R., & Shah, A. (2024). *Virginia data center study: Electric infrastructure and customer rate impacts* (Presentation/technical report). Joint Legislative Audit and Review Commission. https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

[36] Yue, Daniel and Zeng, Yiyang, *The Local Economic Effects of Data Center Entry* (March 30, 2026). Available at SSRN: https://ssrn.com/abstract=6497238 or http://dx.doi.org/10.2139/ssrn.6497238

Finally, a related March 2026 white paper, *The Terms of Power: Inside the New Utility Rates for Data Centers*,[37] finds that emerging data center-specific utility tariffs are increasingly focused on protecting non-data-center customers through mechanisms such as long contract terms, minimum demand and collateral requirements, and explicit cost ring-fencing. At the same time, the paper notes that many tariffs still do little to capture two potentially important sources of value: load flexibility, which could reduce system costs by shifting or curtailing demand during a relatively small number of peak grid-stress hours, and clean energy procurement, which remains absent from many tariffs and therefore leaves natural gas as the default supply option in many jurisdictions.

The paper suggests that while recent tariff design shows meaningful progress on ratepayer protection, there appears to be less consistent integration of features that could further align data center growth with grid flexibility and a cleaner resource buildout.

Taken together, the backward-looking studies provide a nuanced historical record. The current quantitative evidence suggests no indication that ratepayers have subsidized data centers, and more broadly, the relationship between load growth and rising electricity rates is unclear. This underscores both the inherent geographic variation, driven by differences in market dynamics and cost allocation frameworks, as well as the need for further research.

Review of Forward-Looking Studies

Recent forward-looking studies have examined how rapid data center growth could affect future electricity costs, when rising demand might increase costs for other customers, and how regulators and utilities could reduce those risks.

One study from the Federal Reserve Bank of Dallas looks at how the data center boom could affect wholesale electricity prices and, in turn, inflation.[38] The study finds that rapid demand growth, absent stronger customer protections or load flexibility, could increase reliance on more expensive gas- and oil-fired plants during peak periods, raising wholesale power costs until new generation comes online.[39] The study estimates that annual inflation could increase by about 0.04 to 0.13 percentage points by 2030.[40]

These results rely on several simplifying assumptions including that wholesale electricity costs make up about half of customer bills, which can vary widely in practice, and that higher costs are passed through immediately – rather than with typical regulatory lag. It also assumes that there is no new regulatory action to assign these costs to large loads and to shield other customers from rapid load growth, which appears unlikely. The study also does not examine transmission, distribution, or interconnection costs, nor did it consider how these costs are passed through and allocated to different customer groups. Overall, the Dallas Fed study helps illustrate conditions that could increase wholesale electricity prices and highlights the importance of the regulatory framework to effectively allocate costs and protect customers.

The Electric Power Research Institute's recent Powering Intelligence report highlights a broader set of ways data center growth could reshape the U.S. electricity system.[41] The report emphasizes that future load growth is highly uncertain: much depends on how many announced projects are actually built, how quickly new facilities ramp up, and how energy-intensive future AI applications prove to be. EPRI estimates that data centers could account for 9% to 17% of total U.S. electricity demand by 2030, up from about 4% to 5% today. This growth is and will likely continue to be geographically uneven; while today, 20% of Virginia's electricity is consumed by data centers, this share could rise to 39-57% by 2030, and seven additional states could exceed a 20% share by that time in a medium scenario.[42]

Unlike the Dallas Fed study, the EPRI report does not estimate direct effects on retail rates or customer bills. Instead, it focuses on what kinds of generation may be added to serve various levels of growth under different policy and procurement choices to identify least-cost pathways. Under current federal and state policies, EPRI finds that the least-cost pathway is likely to rely heavily on new natural gas generation.[43] In contrast, if

[37] Latitude Intelligence. (2026, March). *The terms of power: Inside the new utility rates for data centers* (White paper). Latitude Intelligence. The Terms of Power: Inside the New Utility Rates For Data Centers | Latitude Media

[38] The Dallas Fed focuses specifically on changes in Personal Consumption Expenditures (PCE) Inflation, which is the US Federal Reserve's preferred inflation metric used to assess consumer price inflation.

[39] Kay, O., Kilian, L., & Taylor, R. (2026, March 5). *Data center boom expected to raise electricity component of PCE inflation.* Federal Reserve Bank of Dallas. https://www.dallasfed.org/research/economics/2026/0305-kay-datacenters

[40] Assumes continued renewable energy development and delayed retirement of some existing power plants as suggested by recent project data from the US Energy Information Administration (EIA). If renewable build-out slows sharply—for example, with little or no additional onshore wind and only 25% of expected solar additions—the inflation effect could be roughly twice as large, reaching 0.13 to 0.23 percentage points by 2030.

[41] Blanford, G., Wilson, T., Bistline, J., & Johnson, N. (2026). *Powering Intelligence 2026: Updated scenarios of U.S. data center electricity use and power strategies* (White paper). Electric Power Research Institute. https://www.epri.com/research/products/000000003002034696

[42] EPRI's Medium Scenario assumes 100% of Data Centers under construction are completed by 2030, as well as 75% of announced projects in advanced stages, and 10% of projects announced that are in early stages.

[43] Build-rates rise from 3.3 GW annually in scenarios without DC demand to 6.6-13.7 GW, a 2x to 4x increase in 2025-2030 depending on the scenario. Natural gas build exceeds past five-year average of 5.7 GW in all least-cost scenarios.

data center demand is paired with 24/7 carbon-free energy goals, the mix shifts toward renewables, batteries, and, where feasible, nuclear power. The study effectively suggests that while data center build-out does not automatically advance the energy transition, it could still help to finance cleaner resource buildout in states that choose that path. In the paper's conclusion, EPRI highlights that supporting projected load growth will require accelerated collaboration across industry, policy makers and local communities, with the potential for data center deployment to align with consumer and policy maker goals.

The Union of Concerned Scientists' (UCS) "Connection Costs" policy brief focuses on another specific but important problem: how grid connection costs are allocated when very large data centers connect directly to the high-voltage transmission system rather than the lower-voltage distribution system.[44] In simple terms, the regulatory framework was built around a world in which most new customers were much smaller and connected through the distribution grid. But when 100–1,000 MW data centers connect at the transmission level, those costs can flow into a part of the rate system overseen by FERC and then be passed through retail rates approved by state commissions, making it much harder to trace and assign them to the customer that caused them. UCS argues that this split oversight between utilities, state PUCs, and FERC creates a regulatory gap and weakens cost-causation principles.

Using PJM planning filings, the brief identifies 130 local transmission projects in seven PJM states tied to data center connections in 2024 and estimates $4.356 billion in related costs. It further finds that 6 of the 130 projects were described as having no cost to other customers, meaning the remaining 124 projects in those seven states possibly fed into the broader transmission cost pool paid by consumers.

The brief carefully notes one limitation: if some of those projects were partly covered through special contracts, line-extension policies, or other customer contributions, those offsets were not transparently credited in the transmission cost development it reviewed. That does not invalidate the concern, but it does mean the brief is best read as evidence of a serious transparency and incentive problem rather than as a final audited measure of net consumer harm. Despite the limited focus of this study on interconnections in PJM, its broader point is valid: where utilities earn returns on transmission investment as they increase their rate base, and where costs can be shared across all ratepayers instead of being assigned to large new loads, the incentives are not naturally aligned with ratepayer protection. This merits a careful review both at the state and federal level to ensure higher levels of transparency and appropriate assignment of cost causation to new large loads.

UCS therefore recommends a more transparent and targeted cost-allocation framework. In particular, it argues that FERC and state PUCs should require utilities to track transmission-level connection costs caused by specific customers, create a separate rate category for customers with direct transmission connections, and ensure that transmission built for a single large load is paid for by that customer or customer class rather than being rolled into costs for all ratepayers. Simply creating a new large load tariff, the brief argues, is not enough unless those connection costs are first clearly separated from broader transmission charges.

UCS' "Data Center Power Play" report takes a wider national view.[45] Rather than focusing on a single cost-allocation loophole, it uses NREL's ReEDS least-cost power-sector model to test how different data center growth assumptions and policy environments affect generation mix, system costs, emissions, and health damages. The study illustrates a range of data center outcomes, ranging from heavier reliance on gas to an expanded buildout of low-carbon resources. While the framing adds useful perspective on different policy trajectories, the results should be interpreted as scenario analysis rather than exact prediction.[46] UCS itself highlights important assumptions and limitations: it assumes only half of announced projects are built, allows projects to take up to five years to reach full load, does not model potentially critical demand flexibility, and relies on a national least-cost model that cannot capture the local reliability, interconnection, and procurement realities that often determine what actually gets built. Despite those limitations, the study broadens the discussion beyond wholesale prices alone and offers complementary policy recommendations: ensure data centers pay their full incremental costs, improve long-term utility planning and transparency, and reform interconnection and transmission rules to reduce barriers for clean resources while avoiding rising emissions and cost shifts to other customers.

[44] Jacobs, M. (2025). *Connection Costs: Loophole costs customers over $4 billion to connect data centers to power grid* (Policy brief). Union of Concerned Scientists. https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20-%20Sep%202025.pdf

[45] Clemmer, S., Chavez, M., Dotson, S., Gignac, J., Sattler, S., & Shaver, L. (2026). *Data Center Power Play: How clean energy can meet rising electricity demand while delivering climate and health benefits* (Report). Union of Concerned Scientists. https://www.ucsusa.org/resources/data-center-power-play

[46] Under its Current Policies case, the model relies more heavily on gas, while under Restored Tax Credits and a stronger Low-Carbon Policy case, more of the incremental demand is met with wind, solar, storage, and other low-carbon resources.

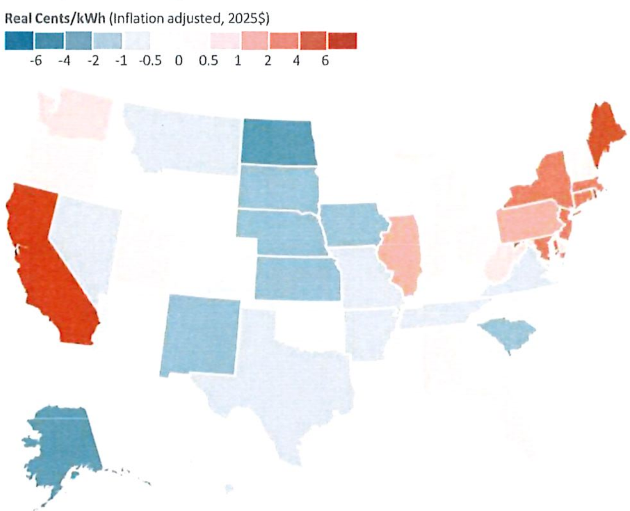
Drivers of Rising Electricity Rates

In reviewing literature on factors that have contributed to rising electricity prices, data centers have been found to have an unclear relationship with electricity rates. In the 2026 LBNL study discussed above, analyzing state-level trends across retail electricity prices from 2019-2025 (inclusive of the residential, commercial and industrial sectors),[47,48] LBNL found that over the last 6 years, nominal electricity prices have risen 29% from 2019 to 2025.

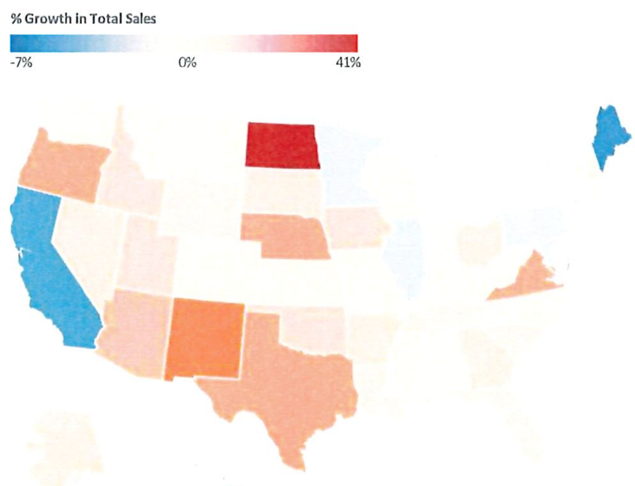
These pricing trends vary between states and for different customer classes, with states on the West Coast and in the Northeast (Maine, New York, Massachusetts, Rhode Island, Pennsylvania, New Jersey, Connecticut, and Maryland) driving US-wide electricity price increases. After adjusting for inflation, 29 states saw price declines from 2019-2024, while 22 states experienced increases.

Figure 5: *LBNL Analysis of State Electricity Prices (Inflation Adjusted) and Electricity Sales*[49]

Change in Average Retail Electricity Prices: 2019 to 2025



Growth in State Retail Electricity Sales: 2019 to 2025



[47] Wiser, R., O'Shaughnessy, E., Barbose, G., Cappers, P., & Gorman, W. (2025). *Factors influencing recent trends in retail electricity prices in the United States.* The Electricity Journal, 38(4), Article 107516. https://doi.org/10.1016/j.tej.2025.107516

[48] Wiser, R. H., Barbose, G. L., Gorman, W., O'Shaughnessy, E., Forrester, S., Donohoo-Vallett, P., Cappers, P., Deason, J., Hledik, R., & Lam, L. (2026). *Retail electricity price trends and drivers: Data update—2026 edition.* Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf

[49] Wiser, R. H., Barbose, G. L., Gorman, W., O'Shaughnessy, E., Forrester, S., Donohoo-Vallett, P., Cappers, P., Deason, J., Hledik, R., & Lam, L. (2026). *Retail electricity price trends and drivers: Data update—2026 edition.* Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf

LBNL concluded that substantial variables correlated with electricity prices included:

+ **Transmission, Distribution, and Business Operation Costs:** Increased spending in transmission and distribution infrastructure has contributed to retail price increases, with significantly higher impacts in CAISO, ISO-NE, and NYISO. For California, wildfire costs are included in the distribution category; storms and wildfires have significantly increased retail electricity prices in some states. Drivers of distribution and transmission investment include expansion; adaptation, hardening, and resilience; and replacement initiatives. Growth in costs has partially been driven by elevated equipment prices above the pace of inflation, due to supply chain constraints.
+ **Wind and solar growth under state Renewable Portfolio Standard programs:** State policies requiring renewable energy deployment were correlated with higher prices. Wind and solar growth that were not subject to the same policies did not have a measurable impact on prices. In particular, net metering (NEM) solar penetration was correlated with increased prices, with an impact as high >2 cents/kWh in California. This is consistent with E3's assessment of cost shift associated with NEM solar, as many utility rate structures do not charge NEM customers the fair share of the fixed infrastructure costs required to serve them.
+ **Natural Gas Dependency:** Electricity prices are sensitive to natural gas prices, depending on the amount of gas-dependent generation within each state. Particularly between 2019-2025, natural gas prices fluctuated substantially with the Ukraine-Russia war, causing similar fluctuations in retail electricity prices.
+ **Load Growth:** In most states, load growth was associated with declining average retail prices between 2019-2025, with prices increasing in states with load decline. In general, load growth can spread fixed costs over large, high utilization customers as discussed in Rate Design Primer. However, PJM was the exception to this trend, with load growth being attributed as a factor in PJM's recent capacity price increases. The impact of load growth on PJM capacity prices is further discussed in the PJM 2025/2026 Case Study section.

LBNL's study offers a valuable overview of macro-trends in electricity prices and highlights correlations between prices and specific variables. Focusing on retail electricity prices is important because they reflect the combined effect of multiple cost factors as discussed above. By contrast, isolating a single component, such as locational marginal prices, offers a much narrower and limited perspective and can be highly sensitive to localized factors, such as fuel price volatility, congestion and weather.[50]

The Charles River Associates report found a similar trend. In analyzing recent average US electricity price trends, prices have increased by 30% over the last five years (inclusive of inflation), but these price increases have primarily been observed in states in the Northeast and California.[51] To determine the cause of price increases in the Northeast and California, CRA compiled data from utility annual financial reports. In California, CRA found that price increases have primarily been driven by increases in wildfire spending and their Net Energy Metering rooftop solar program. In the Northeast, price increases have primarily been driven by purchased power and operations and maintenance (O&M) costs, specifically for utilities that do not own generation. As noted in the primer, customers in wholesale markets are subject to higher volatility than customers of vertically integrated utilities. For example, in the Northeast, retail customers in Pennsylvania and Maryland faced the highest rate increases, in part due to PJM capacity price increases, whereas customers of Dominion Energy (a utility that owns generation) only experienced a minor rate impact.

[50] Saul, J., Nicoletti, L., Pogkas, D., Bass, D., & Malik, N. (2025, September 29). AI data centers are sending power bills soaring [Interactive graphic]. Bloomberg. https://www.bloomberg.com/graphics/2025-ai-data-centers-electricity-prices/

[51] DeCourcey, M., & Saraswat, M. (2026, February 2). Retail rate trends in the US (Report prepared for the Edison Electric Institute). Charles River Associates. https://media.crai.com/wp-content/uploads/2026/02/02092628/Retail-rate-trends-in-the-US.pdf

Select Market Overviews

Data center development has historically been geographically concentrated in a handful of regions.[52] Each operates under distinct regulatory and market frameworks with structural differences that meaningfully shape how large load growth affects wholesale markets, retail rate design, and cost allocation. The following overviews compare and contrast these impacts in more depth for PJM, ERCOT, Georgia, Arizona and Missouri.

PJM Overview

Market Structure and Risk Allocation

PJM operates a centralized wholesale electricity market across 13 Mid-Atlantic and Northeastern states and the District of Columbia. Generation is competitive, with revenues derived from both the energy market and capacity market payments. Transmission infrastructure is planned regionally by PJM but owned and operated by regulated transmission utilities, with costs generally recovered through rates approved by state and federal regulators. Load-serving entities (LSEs), including utilities and competitive retail suppliers, are responsible for procuring capacity and energy to meet customer demand.

PJM's market structure distributes risk across multiple market participants. Generation investment risk is borne largely by private developers, who rely on capacity and energy market revenues to recover costs. However, unlike energy-only markets, PJM's capacity construct shifts some long-term resource adequacy risk to LSEs and, ultimately, retail customers, as capacity procurement costs are typically passed through to end users depending on retail rate design and regulatory frameworks.

For network and generation capacity needed to serve large loads, risk is shared between developers, LSEs, and customers. Transmission upgrades required for interconnection are identified through PJM's interconnection process, with a significant portion of costs directly assigned to the interconnecting generator or load. However, broader regional transmission upgrades and capacity procurement costs are often socialized across all customers.

The primary risks posed by large loads such as data centers in PJM relate to (1) upward pressure on capacity prices in a tightening supply-demand environment, and (2) potential cost socialization through capacity and transmission charges. These risks are partially mitigated through interconnection cost assignments, evolving large load integration reforms, and procurement and hedging strategies employed by LSEs.

Scale of Growth and Market Trends

PJM has experienced increasing projected load growth driven by data centers, industrial expansion, and electrification. The region includes several of the largest data center markets in the world, most notably Northern Virginia, which has seen sustained and concentrated data center development. Recent PJM forecasts indicate a notable increase in peak demand, reflecting the growing influence of large load customers.

[52] CBRE. (2026, February 25). North America data center trends H2 2025. CBRE. https://www.cbre.com/insights/books/north-america-data-center-trends-h2-2025

CASE STUDY

PJM 2025/2026 Capacity Auction

PJM, the ISO/RTO for 13 Mid-Atlantic and Northeastern states and DC, saw a significant price spike in its 2025/2026 capacity auction. Given the substantial load growth in this region, this has prompted questions about the extent that large loads such as data centers have driven this increase.

What Happened?

In PJM's 2024/2025 auction, RTO capacity prices cleared at the lowest point in over a decade (28.92 $/MW-day).[53] Prices dramatically rose in the next auction (2025/2026) by over nine-fold to 269.92 $/MW-day. Policymakers, seeing this rapid increase in prices and market experts expecting the market to clear even higher in the next auction, intervened to keep prices from rising above 340 $/MW-day in the next two auctions (which would have likely otherwise exceeded 500 $/MW-day).[54] These higher realized prices under this new negotiated cap will still impact electricity rates for customers exposed to wholesale markets.[55]

Why Did It Happen?

Fundamentally, capacity prices are a function of supply and demand, but also several recent changes in the PJM capacity market impacted capacity auction clearing prices:

+ **Power Plant Retirements:** There have been a growing number of power plant retirements, with over 9 GW retiring in PJM from 2023-2025,[56] and over 15 GW of announced retirements through 2030.[57] Most of these retirements stem from coal- and gas-fired resources, which have higher capacity accreditation than wind, solar, and battery storage.
+ **Less Reliable Fossil Fuel Resources:** There was a substantial change to the methodology impacting the reliability contribution of fossil fuel resources, thereby lowering the amount of available supply. Following extreme weather events, such as Winter Storm Elliott, during which several gas plants failed to perform, fossil fuel resources were deemed less reliable and assigned lower capacity values for planning purposes.
+ **Change in Reliability Target:** Given past extreme weather events, PJM increased the Installed Reserve Margin (IRM), as well as changed the methodology in which reliability is calculated.
+ **Limitations in New Capacity Additions:** Adding new capacity has also been challenging. Due to lack of sufficient transmission, the cost of interconnection and timeline for interconnection studies have steeply increased, as well as an increase to the cost of new turbines, discouraging developers from building new generation. Historically, it has taken PJM eight years to bring new generation online,[58] prompting reforms aimed at streamlining the interconnection process. Progress continues to lag as from 2023 to 2025, PJM only added 4.7 GW of gas. While it added many other resources, most of those resources have much lower share of accredited capacity. In terms of nameplate capacity, PJM added 1.2 GW of onshore wind, 10.2 GW of solar, and 320 MW of battery storage capacity.[59]
+ **Increase in Forecast Load:** The forecast load in the 2025/2026 delivery year was 153 GW, which was an increase of 3.2 GW compared to the previous year.[60] PJM attributes this load growth to data centers, industrial growth, and electrification, with ~93% of the forecast being driven by forecast data center additions,[61,62,63] as the PJM territory includes several major data center markets, most notably Northern Virginia – the largest in the world.

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[53] Note that these are prices awarded per effective capacity and after reliability accreditation and are not nameplate capacity.

[54] Shapiro, J. (2025, January 28). *Governor Josh Shapiro reaches agreement with PJM to prevent unnecessary price hikes and save consumers over $21 billion on utility bills* (Press release). Commonwealth of Pennsylvania Governor's Office. https://www.pa.gov/governor/newsroom/2025-press-releases/gov-shapiro-agreement-pjm-prevent-price-hikes-save-consumers-ove

[55] DeCourcey, M., & Saraswat, M. (2026, February 2). *Retail rate trends in the US* (Report prepared for the Edison Electric Institute). Charles River Associates. https://media.crai.com/wp-content/uploads/2026/02/02092628/Retail-rate-trends-in-the-US.pdf

[56] PJM Interconnection. (n.d.). *Generation deactivations.* PJM. https://www.pjm.com/planning/service-requests/gen-deactivations

[57] PJM Interconnection. (2023, February 24). *Energy transition in PJM: Resource retirements, replacements, and risks* (Special report). PJM. https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

[58] Weeks, A., Toth Kotwis, S., Siegner, K., & Teplin, C. (2025, November 4). *PJM's speed to power problem and how to fix it.* Rocky Mountain Institute. https://rmi.org/pjms-speed-to-power-problem-and-how-to-fix-it/

[59] Hitachi Energy Velocity Suite

[60] PJM Interconnection, L.L.C. (2024). *2025/2026 RPM Base Residual Auction planning period parameters.* https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction-pdf.pdf

[61] Horger, T., & Keech, A. (2024, August 21). *2025/2026 Base Residual Auction results* (Presentation). PJM Markets & Reliability Committee. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.pdf

[62] Mooney, M. (2024, December 9). *2025 preliminary PJM load forecast* (Presentation). PJM Load Analysis Subcommittee. https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2024/20241209/20241209-item-03 ---2025-preliminary-pjm-load-forecast.pdf

[63] Monitoring Analytics, LLC. (2025, June 3). *IMM analysis of the 2025/2026 RPM base residual auction: Part G* (Revised). https://www.monitoringanalytics.com/reports/reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf

In PJM's Independent Market Monitor's Report,[64] Monitoring Analytics estimated the price impact of reducing data center load growth on prices. In tight supply conditions, reduced data center load growth would have a significant impact on prices. However, tight supply conditions were also caused by a number of factors illustrated above that were unrelated to load growth. Prior to market and programmatic developments observed in the 2025/26 capacity auction and complemented by relatively flat load growth due to energy efficiency investments, capacity prices were too low to effectively signal the need for new reliability-driven resource builds. However, PJM is now experiencing load growth driven by electrification and large loads, such as manufacturing reshoring and data centers, while new supply, constrained by long development and interconnection timelines, has struggled to keep pace. Given these market and programmatic factors, market tightening and higher prices were already forecast, with recent load growth accelerating this dynamic. E3's proprietary analysis in Figure 6 shows that ~50% of the price increases in the 25/26 auction can be attributed to the load growth in PJM, whereas the remaining ~50% can be attributed to changes in programmatic parameters (IRM, FPR, ELCC, VRR curve), supply constraints, and the assumed net cost of new entry (Net CONE) of the assumed marginal capacity resource.[65]

Although data center load growth has contributed to higher capacity prices, the impact on other customers depends on how those increased costs are allocated, which is determined by utilities and regulators through rate design and cost recovery frameworks. Key risk mitigation measures therefore include ensuring increased costs are allocated appropriately across customer classes, helping to limit potential cost shifting.

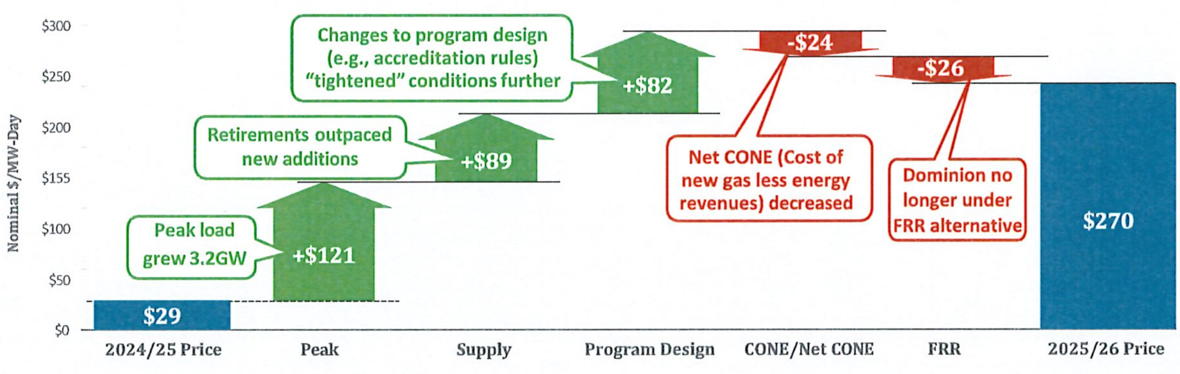
Policy Responses and Customer Risk Protection

While data centers were only one factor amongst many influencing the major capacity price increase from the 2024/2025 to the 2025/2026 auction year, going forward, future forecast data center load growth could drive further capacity price increases in PJM.[67]

To mitigate further price spikes, PJM has implemented short-term emergency measures, such as:

+ **Price Cap and Floor:** Following an agreement in January of 2025 with the governor of Pennsylvania, a temporary price cap and floor was approved for the next two PJM capacity auctions (2026/2027 and 2027/2028 delivery years). This was meant to ensure that customers aren't paying for elevated capacity prices while more long-term reforms are implemented.
+ **Inclusion of Retiring Power Plants in Supply Calculations:** Previously, power plants that are slated for retirement but are kept operational ("reliability must run" units) were excluded from supply calculations in capacity price auctions. New PJM market reforms, which have been approved by FERC, will allow those power plants to be included in capacity price auctions.

Figure 6: E3 Analysis of the Capacity Price Auction Changes between 2024/2025 and 2025/2026[66]



[64] Monitoring Analytics, LLC. (2025, October 1). Analysis of the 2026/2027 RPM base residual auction: Part A.

[65] Fixed Resource Requirement (FRR), Effective Load Carrying Capability (ELCC), Variable Resource Requirement Curve (VRR) Curve. While the case study above is focused on the 25/26 auction, E3 also conducted an analysis of the drivers contributing to the incremental capacity price increases in the 26/27 and 27/28 auction, looking at the price levels that PJM itself calculated that the auction would have cleared absent the lower negotiated price cap. Peak load increases drove much of the incremental price increase in the 26/27 auction (which was somewhat mitigated by additional offered resources); 27/28 price increase is more difficult to determine, as it is difficult to isolate whether it was limited supply growth or peak load growth that contributed to failure of meeting the reliability requirement.

[66] Graphic derived from a reconstruction of PJM capacity auctions using a simplified supply–demand framework in which ELCC-adjusted capacity supply intersects an administratively defined VRR curve to determine clearing prices. The model decomposes price changes across five primary drivers (peak load, supply CONE/Net CONE, program design, and FRR) by running counterfactual scenarios and averaging impacts across all permutations of factor ordering (i.e., a Shapley-style attribution approach). Net CONE (cost of new gas less energy revenues), in addition to Gross CONE, informs the demand curve, which impacts where capacity prices clear in the auction. Implied ICAP values and category-level adjustments are estimated from publicly reported PJM data and supplemented with structured assumptions where disclosures are incomplete, including calibration to align ICAP, UCAP, and observed auction outcomes. FRR capacity is adjusted to reflect its effective participation in auction supply. Results represent an internally consistent decomposition of observed outcomes and are intended to illustrate relative driver contributions under a controlled framework; they do not reflect unit-level bidding behavior or fully dynamic market responses to price.

[67] Mooney, M. (2024, December 9). *2025 preliminary PJM load forecast* (Presentation). PJM Load Analysis Subcommittee. https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2024/20241209/20241209-item-03 —-2025-preliminary-pjm-load-forecast.pdf

On the demand side, PJM has also created "Critical Issue Fast Path" (CIFP) which is an accelerated stakeholder process to reform the large load integration process, and has proposed three potential market design frameworks. Other measures for consideration include curtailment obligations, contractual commitments to reduce speculative load in capacity planning, and expedited interconnection for loads paired with generation (i.e., "bring your own generation") to further help alleviate supply constraints. Moreover, PJM has noted that current load forecast is likely elevated and it expects to see a reduction in forecasted demand as it reforms its forecasting approach to further align its future load forecasts with expected realities.

Risk mitigation can also be embedded into rate design as previously discussed to reduce the potential of stranded assets if projected load doesn't materialize or underperforms. In addition, utilities can manage exposure through hedging and other procurement strategies to limit price volatility and risk.

State Governors and the White House are closely scrutinizing this issue and in January 2026, released a "Statement of Principles Regarding PJM" to PJM and FERC, outlining a set of suggested emergency reforms to address capacity shortages and mitigate future price increases. These included providing 15-year revenue certainty to new generation (such as via a Reliability Backstop Auction, or "RBA"), allocating costs to data centers that have not self-procured or agreed to be curtailable, extending the price collar to the next two auctions, improve load forecasting to avoid building for speculative loads, and accelerate generator interconnection studies especially for resources in the backstop auction.[68]

In April 2026, PJM responded to the Statement of Principles Regarding PJM with its own proposal that provides more details about the proposed Reliability Backstop Auction.[69] Specifically, PJM proposes a one-time additional capacity procurement measure to address the rising gap between forecasted load and delivered capacity.

+ **Bilateral Contracting Stage:** A first step establishes a bilateral contracting phase (planned for September 2026 through March 2027), where PJM acts as confidential matchmaker between interested parties and aims to keep as much additional capacity and newly procured power outside of the auction framework.[70]
+ **Central Procurement Structure:** Any parties unable to contract their capacity through bilateral contracting are allowed to bid into a second, centralized, pay-as-bid auction in 2027 to procure the remaining resources. PJM will act as counterparty on behalf of Electric Distribution Companies estimating around ~15 GW of new capacity procured in this auction.[71]

The proposed backstop auction is attractive for generators due to the long-term capacity revenue security, and it would support the procurement of additional capacity that cannot be procured under the normal, price-capped regular capacity auction. This would help ease some of the supply constraints in PJM. However, this new measure would not solve other key bottlenecks such as equipment and interconnection queue backlogs. The tight June 2031 interconnection deadline also means that many of the current parties interested in developing new capacity are unable to participate, which would limit the amount of new capacity procured in the backstop auction. Relating to auction design, the 2-15-year capacity contracting schedule would lead EDC's to adjust their large load rates and implement requirements to post larger securities and enter long-term offtake agreements. This would allow EDCs to reduce the risk of sudden exits of large loads, which would negatively impact ratepayers. When it comes to capacity price impacts, the longer term contracting option and revenue security of the RBA will likely mean that average bid prices are lower than they would be if the current regular annual auctions were uncapped. Whether average prices fall below the price cap or the individual pay-as-bid price range remains uncertain and requires further quantitative analysis. The impact of this backstop auction on regular capacity auction prices also remains unclear and will depend on the remaining gap between load forecast and procured capacity.

Independent of the uncertain outcomes of the Reliability Backstop Auction and potential PJM market reforms, capacity prices will continue to be driven by multiple factors in addition to load growth such as the pace of new generation interconnection, retirement schedules and market design choices. It's important to note that capacity prices are only one category of costs that impacts retail rates, and utilities ultimately allocate costs across different rate classes to determine the final impact on rates and requires careful considerations.

[68] U.S. Department of Energy. (2026, January 15). *Statement of principles regarding PJM* (PDF). U.S. Department of Energy. https://www.energy.gov/documents/statement-principles-regarding-pjm

[69] PJM Interconnection. (2026, April 16). *Critical Issue Fast Path – Reliability Backstop Procurement PJM Proposal* (PDF). https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260416/20260416-item-05---pjm-reliability-backstop-procurement-proposal---paper.pdf

[70] By allowing resources and loads to contract outside the regular market, this eases the pressure on Electric Distribution Companies (EDCs) to deal with long-term off-take and procurement risk as well as ratepayer impacts for a potentially important percentage of new load and capacity.

[71] The auction is scheduled as pay-as-bid for contract terms ranging from 2 to 15 years. Bidders must have a commercial operation date no later than June 1st, 2031. Any entity contracted through this mechanism will automatically be added to the regular capacity auctions for the duration of its contracting period and paid at their initial clearing price. This is akin to a Contract for Difference (CfD) structure, where the entity is paid more than the regular auction price, if its contract value sits above and less in case that it sits below the annual clearing price.