Understanding the Drivers of Rising Electricity Rates and the Role of Data Centers

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Prepared by:

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Authors & Acknowledgments

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Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the power sector in North America. For over 30 years, E3's data driven analysis and unbiased recommendations have been utilized across the power industry by the utilities, regulators, government agencies, project developers, investors, and non-profit entities. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

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Report in Brief

As electricity use in the U.S. grows for the first time in decades, many households are seeing higher energy bills. Data centers, in part due to their size and visibility, have become an easy focal point in discussions of rising costs but the evidence suggests a more complex picture. Demand is increasing due to electrification, industrial reshoring, and data center expansion. While this growth has coincided with rising retail electricity rates in some regions, the relationship between load growth and electricity retail rates is complex and must be interpreted carefully.

What the data tell us:

- **Retail rate outcomes are influenced by broader supply-demand dynamics, market design choices, fuel cost volatility, generation retirements, inflation, and other utility investments (such as grid modernization, wildfire mitigation, policy compliance) —not load growth alone.**
- Of the quantitative analyses conducted to date (See Appendix A.1), there is **no evidence that data centers have been historically subsidized by other customers** under existing rate structures. Regular updates to utility cost allocation across customer classes will be critical to continuing to prevent cost shifting amid rapid load growth.
- Some analyses found that **data centers generate *surplus* utility revenues** from paying more than the cost to serve them, which can potentially ***lower* electric rates for other customers**.
- State-level analyses show **no clear relationship between load growth and rising rates**. States such as Texas and Virginia with the *largest* increases in load (largely driven by data centers) had the smallest rate increases, while states like California and New York saw the largest price increases but a reduction in load. In the PJM market in the Mid-Atlantic region, data center-driven load growth is one of several factors putting upward pressure on capacity market prices, alongside market design changes and power plant retirements, and resulting customer impacts will depend on how utilities allocate costs between data centers and other customers, subject to regulatory approval.
- **As the pace of data center growth has accelerated, so too has the evolution of regulatory and policy tools**, particularly rate design, to manage impacts. This trend is reflected in at least 38 new large load tariffs established between 2018 and 2026 to more clearly assign customer-specific costs and mitigate ratepayer risk. 30 were implemented in 2025-2026 alone, underscoring the accelerating pace and adaptation in response to load growth.[1]

Gaps in literature and areas for further investigation:

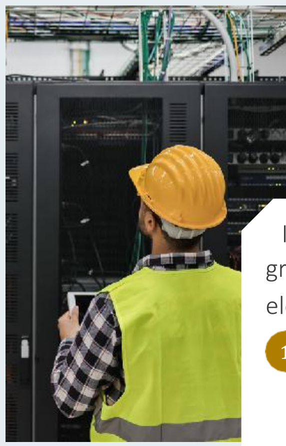
- Only a **few quantitative** studies have been conducted, examining this relationship between data center growth and retail electricity rates, with most looking at historical data. Further, many **rely on correlation** rather than establishing *causal* relationships.
- How well risk mitigation tools will perform over time.
- How processes (such as infrastructure planning, regulatory lag, cost allocation, and market design) will change in response to rapid and sustained load growth.
- While the quantitative studies to date **have not found evidence** of systematic cost shifting, research gaps remain and the risk is not absent.

In short, there is no quantitative evidence to date that data centers have historically been subsidized by other customers, and historical load growth has been found to be only one driver out of many others contributing to retail rate outcomes. As the pace of data center growth has accelerated, regulatory and/or policy tools have rapidly adapted as well to both accommodate higher levels of growth and manage that growth's potential impacts. Implementing these tools across the country will be vital to ensuring ratepayer protections amid this load growth and can even provide ratepayer benefits as well.

[1] E3 evaluation of large load tariff data from Halycon. Select measures quantified here include minimum monthly demand payments, contribution in aid of construction (CIAC), exit fees, minimum load factor >50%, and long-term contract years >10. Inclusion of other measures such as collateral requirements would increase these estimates. See Appendix A.2 for the referenced set of tariffs.

Executive Summary

The relationship between load growth and electricity retail rates is more complex than often conveyed in public discourse. Retail rates reflect a combination of generation, transmission, distribution, policy, and market dynamics – not simply changes in demand- and while load growth can influence system costs, it is only one of many factors. Understanding the role of large loads requires a more nuanced, evidence-based assessment that accounts for these multiple interacting drivers, and is especially important context when identifying ways to manage costs and maintain customer affordability.



E3's review of the few quantitative analyses on this topic did not yield evidence that other utility customers are subsidizing data centers.

- Notably, E3's study for the Joint Legislative Audit and Review Commission (JLARC) in Virginia – the world's largest data center market – found no evidence of a historical or present-day cost shift from data centers to residential or small commercial customers.
- Moreover, some studies found data centers can potentially *lower* electric rates for other customers, by paying not only the incremental cost to serve them but also paying embedded fixed costs, which can be used to create downward pressure on rates. An E3 study examining Amazon data centers across four diverse utility territories found, on average, each site generated $3.4 million in net surplus (i.e., revenues exceeding costs) that could help offset costs for other customers.
- More broadly, E3 found no clear relationship between load growth and rising electric rates. In the economic consulting firm Bates White's recent study, states such as Texas and Virginia with the *largest* increases in load (largely driven by data centers) had the smallest rate increases, while states like California and New York saw the largest rate increases but a reduction in load. Lawrence Berkeley National Lab's (LBNL) recent study found similar results, except in the PJM region.
- A recent working paper from Georgia Tech identified a small increase in electricity retail rates on average across a subset of US counties after initial data center entry, but further investigation into rate dynamics and other regional differences is required to more definitively estimate the impact of today's large load clusters.
- E3 conducted an analysis of the change in capacity prices between PJM's 2024/2025 and 2025/2026 auctions and found that load growth (primarily data centers) accounted for ~50% of the increase while other changes, such as market design updates and power plant retirements, drove the other ~50%.

In its review, E3 found a number of factors, beyond load growth alone, have been major contributors to rising electric rates:

1. **Inflation:** Recent inflation has significantly increased the cost of labor, materials, and financing, directly increasing the amount of revenue utilities need to collect to recover their investments.
2. **Natural Gas Price Volatility:** Natural gas prices have become more volatile and regions reliant on gas-fired generation are particularly exposed to this price volatility.
3. **Wildfire Mitigation and Resilience Investments:** Wildfire-related mitigation spending and grid hardening more broadly now represent a significant and growing share of utility spending to respond to and protect against extreme weather events.
4. **Grid Modernization:** Utilities have increased investment to replace aging infrastructure, comply with policies, and modernize the grid.
5. **Market Design and Supply Dynamics:** In wholesale markets such as PJM, capacity price volatility has also been driven by market design and supply-side factors, including power plant retirements, reduced accreditation of fossil resources, higher reliability targets, planning/forecasting gaps, regulatory lag, permitting barriers, and interconnection backlogs.

While there are many factors at play, the risk of increasing rates and cost shifting from load growth is real. E3 examined forward-looking studies highlighting potential cost pressures under rapid load growth, including tighter electricity supply, accelerated infrastructure needs, and stressed regulatory processes, but these challenges are neither novel nor unmanageable. There is a range of tools to address these dynamics and support equitable cost allocation, including robust tariff protections, timely cost-of-service updates, federal and state coordination, data-driven monitoring of impacts, and improved forecasting and planning processes.

Markets across the US illustrate a range of approaches to addressing load growth:

- In **PJM**, recent capacity price increases reflected tightening supply conditions with load growth as one but not the only contributor. PJM has responded by advancing proposals to reform its market and processes, and in parallel the 13 PJM-state governors and federal officials issued a Statement of Principles calling for more immediate and structural reforms.
- **Texas** has experienced significant load growth in recent years and developed specific policies such as Senate Bill 6, without disproportionate retail rate increases to date.
- In **Georgia**, regulators have responded to rapid data center growth by strengthening long-term contract requirements and minimum billing protections to reduce stranded cost risk.
- **Arizona** is experiencing rapid, large-scale data center-driven load growth, and regulators and utilities have responded by refining rate design and contractual protections to better align with cost causation and limit cross-subsidization risks.
- **Missouri** is one of several emerging markets that has proactively established large load tariffs and long-term contractual requirements with extensive stakeholder involvement to preempt cost shifts and mitigate stranded cost risk.

These varied responses underscore that affordability outcomes can and are shaped by market conditions, adaptive planning and regulatory action, and that impacts will vary across regions rather than follow a single national pattern.

Attributing rising electricity bills to a single, visible source such as data centers oversimplifies a more nuanced reality. The financial pressures facing the electric system reflect a range of economic, policy and market factors, and the conversation should therefore shift beyond generalized claims and instead focus on creating a framework for responsible load growth.

E3 recommends the following approach, with more details included in the full report:

- **Strengthen planning and forecasting.** Implement techniques to reduce the risk of speculative overbuild, stranded infrastructure, and unnecessary customer exposure.
- **Leverage tailored large load tariffs and regularly update cost allocation to appropriately reflect the scale and pace of load growth.** Use risk mitigation tools and timely cost allocation updates to align cost responsibility with evolving system conditions and mitigate risk.
- **Enable innovative supply and load integration models.** Leverage approaches such as load flexibility, “bring your own generation” models, streamlined permitting, and utility data sharing (such as on available capacity and timelines) to better integrate large loads while reducing system costs.
- **Close research gaps with targeted analysis.** Expand data collection and targeted analyses to better understand long-term impacts and inform evidence-based decision-making.

With thoughtful, market-specific approaches, regulators can support economic growth while protecting customers and ensuring fair cost allocation.

Overview of Approach

This paper applies a structured, evidence-based approach to evaluating the relationship between data center load growth and electricity rate outcomes. It begins with a primer on how electric systems are planned, financed, and regulated, including how utilities forecast demand, make investment decisions, and recover costs through retail rates. This foundation is critical for interpreting existing studies, as retail electricity prices reflect a combination of generation, transmission, and distribution investments, market dynamics, and regulatory processes rather than changes in load alone.

Building on this foundation, the paper reviews the available quantitative research from 11 studies on recent electricity rate trends and the role of data centers, drawing from both backward-looking empirical studies and forward-looking analyses. This review is complemented by interviews with four industry experts to provide additional context on how these dynamics are evolving in practice. Taken together, these inputs are used to develop a structured lens for evaluating when and how large load growth may influence affordability outcomes, including the role of system cost impacts, cost allocation, and rate design. The paper also highlights the range of tools available to mitigate potential risks, emphasizing that outcomes depend not only on load growth itself, but on how effectively policy, planning, and regulatory processes adapt over time.

Primer: How Power Markets Work

Before delving into the quantitative studies, this paper begins with a primer on the fundamentals of power markets and utility rate design. Establishing this foundation provides the critical framework needed to assess the existing literature and more rigorously evaluate when and how large loads may influence retail prices, and under what circumstances they may produce neutral or even beneficial effects for other customers.

Electric power markets exist to solve a physical constraint: electricity must be produced when it is consumed. Because development and deployment of large-scale storage technology systems remain limited, system operators must match supply and demand continuously. The market and regulatory structure that govern this process determines who builds generation, how investment risk is allocated, how prices are determined, and ultimately how customers pay for service.

Utility Models in the US

Utility structures generally follow one of two basic models that vary by state. The choice determines whether regulation or competition drives generation investment.

Vertically Integrated States

In vertically integrated states, a single entity (utility) owns and controls generation, transmission, and distribution infrastructure within a defined service territory. A state public utility commission (PUC) regulates the utility's retail rates and reviews its investment decisions.

The utility forecasts demand, plans new resources, builds or procures those resources, and is permitted to recover prudently incurred operating costs, depreciation, taxes, and an authorized return on invested capital. Capital investments are included in the utility's rate base, whereas the approved return on equity is applied to that base. Regulators examine whether the utility acted prudently through regulatory proceedings.

An Integrated Resource Planning (IRP) process is conducted by the utility to evaluate demand forecasts, resource planning, fuel price assumptions, reliability requirements, and policy mandates to determine a least-cost portfolio over a long-term planning horizon.

This structure relies on regulatory oversight rather than competition to discipline investment. Customers bear much of the long-term investment risk because approved costs flow into rates. While vertically integrated utilities may participate in bilateral or organized markets for short-term energy balancing, they retain the primary responsibility for ensuring resource adequacy and system reliability within their service territory.

Wholesale Market States

In states with wholesale markets, utilities procure generation through competitive wholesale markets, where independent power producers build and operate plants. Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) operate the wholesale electricity markets and manage the transmission system within defined regional footprints. They administer market rules, conduct economic dispatch, and oversee reliability planning, but they do not regulate retail rates or directly site generation facilities.[2]

Given this structure, utilities' generation costs are driven by market-clearing prices rather than traditional cost-of-service regulation. Utilities also usually retain ownership of transmission and distribution assets and continue to operate under regulated retail rate structures.

Under this structure, investment risk is more exposed to market outcomes than in vertically integrated models. Generators rely primarily on market revenues (as opposed to guaranteed rates), placing greater risk on these private investors. The overall market structure's effectiveness ultimately depends on whether its rules produce prices that both support efficient short-term dispatch and sustain adequate long-term investment. Accordingly, this next section focuses on the market mechanisms that generate these price signals, which play a central role in how revenues are earned, investment decisions are made, and overall market performance and reliability are determined.

[2] The RTOs and ISOs operate under oversight of the Federal Energy Regulatory Commission (FERC), which regulates interstate transmission and wholesale markets, approving market rules and tariffs and ensuring wholesale rates are just and reasonable.

Wholesale Market Fundamentals: Energy and Capacity Markets Overview

In energy markets, generators are compensated for producing megawatt-hours. Generators submit offers reflecting the price at which they are willing to supply energy. The system operator stacks these offers from lowest to highest cost to meet forecasted demand for each hour. The highest-cost unit needed to meet demand sets the market-clearing price, and all dispatched units receive that price, reflecting the marginal unit.

This process reflects basic supply and demand. As demand rises, the operator must dispatch higher-cost units, which increases the clearing price. As demand falls, lower-cost units set the price. Scarcity pricing, occurring as prices rise (sometimes up to an administrative cap), signals the value of additional supply and in turn encourages new build.

Some regions supplement energy markets with capacity markets. Capacity markets pay resources for committing to be available during future peak periods. The product is not energy produced, but readiness to produce. Load-serving entities (e.g., utilities) must procure sufficient capacity to meet projected peak demand plus a reserve margin (effectively a buffer to account for forecast error). The price is set through a centralized auction, and this revenue stream helps ensure that resources which run infrequently but are critical during peak periods remain available during times of grid stress.

RTOs must maintain a balance across these resources, with supply equaling demand at every moment; any imbalances affect system frequency and can damage equipment or trigger outages. RTOs use economic dispatch to help maintain this balance, selecting the least-cost combination of available resources that can meet demand while respecting transmission limits and reliability constraints.

Rapid growth in large electricity loads can place upward pressure on retail electricity prices by tightening supply-demand balances. As higher-cost generation is dispatched to meet rising demand, wholesale prices increase, and those costs can flow through to all customers, not just the new load, much like prices rising in housing markets when demand outpaces supply. These effects are often transitional rather than permanent, with the magnitude and duration depending on how quickly supply can respond (through new generation, storage, transmission upgrades, or more flexible load) and whether regulatory, permitting, or interconnection barriers delay that response. Moreover, the effects depend on how costs are allocated, both to ensure new loads pay in line with the costs they impose on the system and to potentially create incentives for large loads to minimize their grid impacts, such as through time-of-use pricing or load flexibility, to reduce costs.

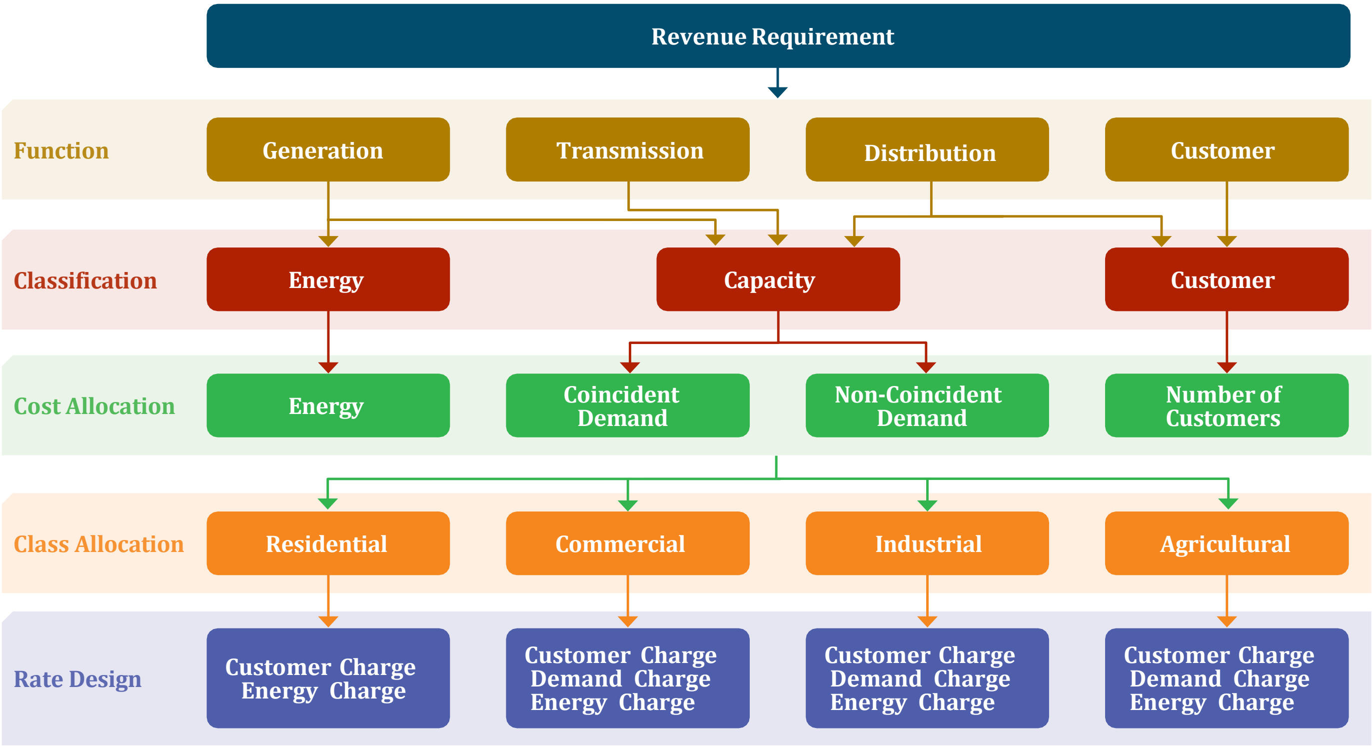
Primer: Retail Rate Design and Cost Allocation

How Are Electric Rates Developed?

Retail rate design is the process through which a utility recovers its total costs from customers. This total cost, known as the revenue requirement, represents the amount the utility must collect to provide reliable service and maintain financial stability. Utilities invest in generation (if vertically integrated), transmission, and distribution infrastructure based on forecasts of future demand and system needs. Under cost-of-service regulation, those investments along with operating expenses are incorporated into the utility's annual revenue requirement and recovered over time through depreciation and an authorized return on invested capital. Utilities also recover purchased power costs, which are typically passed through to customers without earning a return.

Cost-of-service analysis (COSA) determines how that total revenue requirement is allocated across customer classes, with the goal to ensure that costs are allocated to customer classes in a way that properly reflects underlying cost drivers. The core steps are shown in Figure 1. The process first functionalizes costs by system function (generation, transmission, distribution, and customer-related costs), then classifies them by cost driver (primarily energy-, demand-, or customer-related), and finally allocates them to customer classes based on measures such as energy consumption and contribution to peak demand. These results establish each class's revenue responsibility. Rates are then designed to recover that responsibility through a combination of fixed charges, volumetric energy charges, and demand charges. While COSAs provide a cost-based foundation, final rate structures often balance additional objectives such as affordability, simplicity, and policy goals, meaning that rates may not perfectly mirror pure cost signals.

Figure 1: *Utility Rate Design Process*[3]



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[3] Riu, I., Patel, K., Mettetal, L., Santoni-Colvin, M., Platter, H., Greszczuk, S., Cardona, J., Bertrand, L., Spencer, S., & Ramirez, S. (2025). *Tailored for scale: Designing electric rates and tariffs for large loads: A guidebook of industry best practices and examples from real-world Amazon data center case studies* (White paper). Energy and Environmental Economics, Inc. (E3). https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

Retail rate changes, including the underlying assumptions used, are reviewed, challenged, and approved through robust and formal regulatory proceedings that are designed to ensure fairness, transparency, and adherence to cost-causation principles. In both vertically integrated and restructured states, regulated utilities file detailed rate cases or cost-of-service studies with their public utility commissions. In vertically integrated states, these cases cover the full cost of providing electric service, including generation, transmission, and distribution, whereas in restructured states like New York, rate cases primarily address transmission and distribution costs, with generation costs determined through wholesale markets and passed through to customers. These proceedings typically involve thousands of pages of testimony, data requests, financial schedules, engineering studies, and expert analysis. Multiple stakeholders participate, including state consumer advocates, industrial customer representatives, environmental organizations, independent experts, and in some cases large load customers themselves. This level of scrutiny reflects the importance of rate design decisions and underscores that questions of cost sharing and potential cost shifting are actively debated and carefully evaluated within an established regulatory framework.

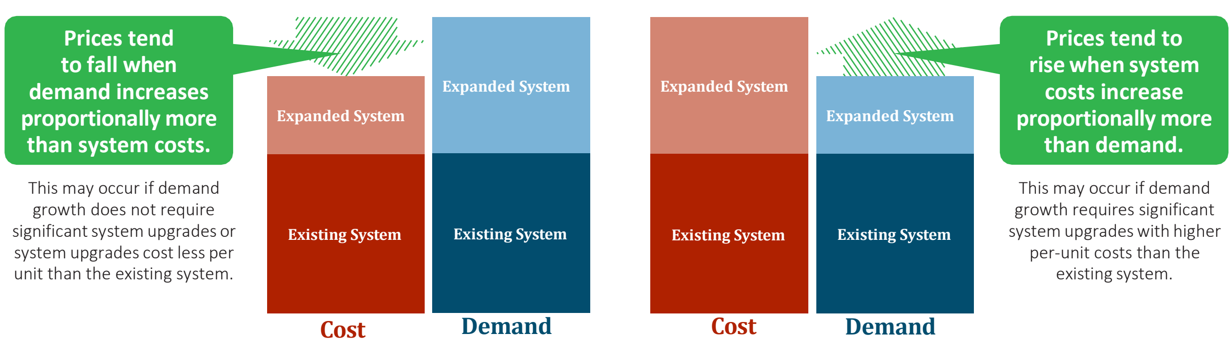
Why Rates Rise (or Fall), and What Is Cost Shifting?

Cost shifting is when one group of customers pays more than the costs they cause and are responsible for, effectively subsidizing another group. In the context of new loads, cost shifting would occur if the costs attributable to serving that load, including both direct infrastructure costs and broader system impacts, are not fully recovered from that customer and instead are allocated to other customers through higher rates for those customers.

It is important to distinguish cost shifting from overall rate impacts. New load growth can affect total system costs and therefore rates, even when costs are allocated in a manner consistent with cost causation. At a high level, the impact of new load on average rates depends on the relationship between total system costs (i.e., the revenue requirement) and total billed sales, as illustrated in Figure 2 below. If the costs required to serve the new load increase the revenue requirement faster than total sales increase, average rates may rise. Conversely, if sales increase more rapidly than total costs, fixed system costs are spread across more kilowatt-hours, creating downward pressure on average rates. This can be a major benefit of high load factor customers such as data centers: they can improve utilization of existing, underused system capacity and support fixed cost recovery, helping to reduce the cost burden on other customers. In fact, a 2026 study from the Brattle Group demonstrates how greater utilization of the existing electricity system could significantly improve affordability, saving more than $100 billion in the next decade, while enabling load growth and benefitting consumers by spreading costs over a larger sales base.[4]

Importantly, these rate impacts are not, by themselves, evidence of cost shifting. Cost shifting arises only when costs are not assigned or allocated in proportion to cost causation—for example, if costs driven by a new load are not fully reflected in that customer's cost responsibility and are instead borne by other customers. Persistent differences between revenues and cost responsibility may indicate that costs are not being allocated in proportion to cost causation, resulting in cross-subsidies between customers. However, short-term differences can also arise due to timing lags, rate design features, or market structures, and do not necessarily imply longer-term cost shifting. These outcomes emphasize the importance of updating cost allocation assessments as often as possible, particularly in the face of substantial and rapid load growth.

Figure 2: *Illustrative System Rate Impact Dynamics*[5]



[4] Hledik R., Lam L., Peters, K. (2026). *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability*. The Brattle Group. https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf

[5] 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

How the Regulatory System Protects Customers

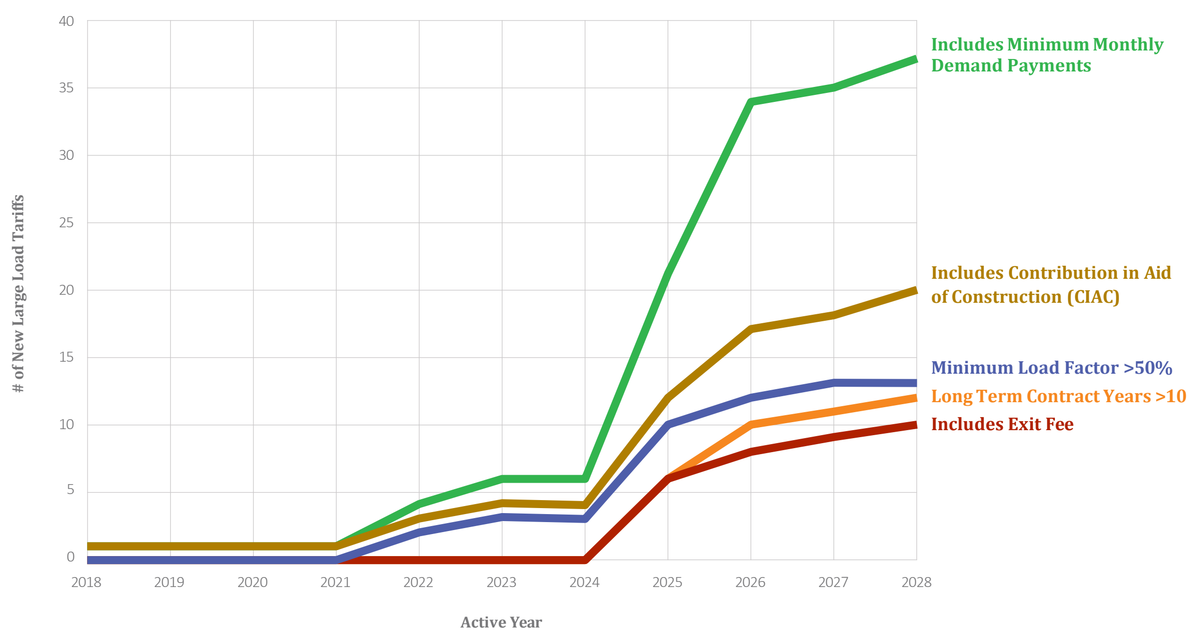
The regulatory framework includes multiple safeguards to prevent cost shifting and ensure customer protections and equitable outcomes.

First, as described in the previous section, core principles of equitable rate design aim to align customer payments with the costs they impose on the system, while also balancing other policy objectives. These costs include existing (embedded) system costs as well as incremental (marginal) system costs. Reflecting marginal costs help ensure that new load does not impose uncompensated costs on the system. Embedded cost allocation methods further distribute fixed costs based on cost-causation principles, aligning class revenue responsibility with underlying drivers such as energy consumption and peak demand. Specific measures for transmission cost allocation are discussed below.

Second, utilities and regulators have begun to employ risk mitigation tools in large load tariff design to manage longer-term uncertainties, including stranded asset risk. Large loads can carry uncertainty regarding pace, scale, or longevity. To manage this risk, utilities may implement minimum demand charges, take-or-pay provisions, long-term contract terms, credit requirements, refundable deposits, capacity reservation charges, and interconnection cost assignments. For example, contribution in aid of construction (CIAC) involves customers paying upfront for dedicated facilities (substations, lines, transformers), which acts as private grid investments that benefit the broader community, rather than just managing liability. These mechanisms ensure that if load does not materialize as forecasted or exits early, unrecovered costs are not shifted to other customers. The next section provides an overview of these tools in more detail.

Moreover, these tools are increasingly being implemented. Figure 3 shows, for select customer protection measures, the cumulative counts of new large load tariffs by active year, demonstrating the accelerating pace of adoption as utilities and regulators respond to large load growth. The full set of tariffs referenced here are provided in Appendix A.2, and may not be capturing all tariffs.

Figure 3: *Cumulative Counts of New Large Load Tariffs by Customer Protection Measures, by Active Year*[6]



[6] Graphic developed by E3 using Halcyon data

Third, thoughtful rate design can also unlock the potential benefits of load growth. When incremental revenues exceed incremental costs, and include a contribution to embedded system costs, these fixed system costs can be spread over a larger sales base to reduce average rates for existing customers. High-load-factor customers in particular can contribute steady revenue streams that improve cost recovery and system utilization. Properly structured tariffs and allocation methodologies ensure that these benefits are realized while maintaining cost discipline and financial stability. In contrast, upward rate pressure can occur when incremental infrastructure investments increase the utility's revenue requirement faster than sales grow, or when new load does not contribute sufficiently to marginal and allocated embedded costs. In such cases, fixed costs are spread across a broader base without corresponding revenue support, raising the average cost per unit of electricity for other customers. Updates to how costs are allocated can address these rate impacts across customer classes, although in the short-term there may be regulatory lag. These dynamics underscore the importance of aligning revenues with cost causation and implementing appropriate risk mitigation tools.

More broadly, frequent updates to cost allocation practices should be a cross-cutting priority given a fundamental pacing mismatch: technology and load growth evolve faster than regulatory institutions, outstripping traditional planning and rate case cycles.[7] Processes such as IRP proceedings are not built for speed, creating tension with the speed-to-market needs of large load customers and potentially delaying necessary adjustments, which can increase risk.[8] Identifying ways for regulatory frameworks to keep pace and adapt will be essential to addressing rate impacts.[9] For example, periodic review of allocation factors, demand determinants, and infrastructure cost recovery helps ensure that rate structures remain aligned with evolving system conditions.[10]

Regulatory flexibility is also essential. Tariffs are increasingly designed to allow for adjustments if pricing, riders, or minimum bill structures do not perform as expected, and their success will depend on how well they adapt in practice.[11] Given uncertainty around long-term impacts, embedding flexibility, protections, and opportunities for renegotiation can improve risk and cost allocation over time.[12] More broadly, the scale and pace of recent large load growth may warrant revisiting traditional cost accounting frameworks and reexamining core principles to ensure they remain fit for today's conditions and are adaptable to future changes.[13]

In short, cost shifting is not determined by the size of a load alone, but by whether revenues meet incremental costs and whether appropriate risk mitigation and allocation tools are in place. When structured properly, new large loads can be neutral or beneficial to other customers while maintaining cost discipline and financial stability.

Key Risk Mitigation Measures in Large Load Tariff Design

To manage uncertainty and protect existing ratepayers, utilities have developed a broad toolkit of risk mitigation mechanisms. These tools are not theoretical; they are widely and increasingly embedded in large load tariffs and contracts across jurisdictions to protect other customers. The appropriate combination of mechanisms depends on factors such as load size relative to the utility system, market structure, creditworthiness, and policy priorities. Importantly, stronger risk mitigation reduces the likelihood of stranded costs but may also limit the opportunity for shared benefits, such as downward rate pressure, by reducing the role of socialized approaches that enable system gains (e.g., improved asset utilization, fixed cost recovery) to translate into broader benefits. Effective rate design therefore balances risk protection with economic development and system efficiency objectives.

7 Interview with Lynne Kiesling, Northwestern University, April 2026
8 Interview with Kevin Gunn, Evergy, April 2026
9 Interview with Lynne Kiesling, Northwestern University, April 2026
10 Interview with Kevin Gunn, Evergy, April 2026
11 Interview with Kevin Gunn, Evergy, April 2026
12 Interview with Kevin Gunn, Evergy, April 2026
13 Interview with Lynne Kiesling, Northwestern University, April 2026

The following outlines a menu of options for utilities to consider:

Minimum Revenue Protections

- **Minimum demand charges** require customers to pay for a minimum percentage (e.g., 70–90%) of contracted or installed capacity, even if actual usage falls below that level. This measure protects against underutilization of infrastructure.
- **Take-or-pay provisions** obligate customers to pay for reserved capacity regardless of actual consumption. This measure ensures cost recovery even if load temporarily declines.
- **Minimum bills** guarantee a floor level of annual revenue from the customer. This measure stabilizes recovery of fixed generation, transmission, and distribution costs. Minimum bill provisions ensure baseline revenue recovery even if actual demand underperforms, often requiring customers to pay for a substantial portion of their contracted load.
- **Capacity reservation charges** require customers reserve a specified amount of system capacity and pay for it whether used or not. This measure aligns payment with infrastructure sizing decisions.

Contractual Commitment Mechanisms

- **Long-term service agreements** require multi-year commitments (often 5–15+ years). This measure reduces risk of early exit after infrastructure is built.
- **Exit fees and early termination charges** impose financial penalties if a customer leaves before contract expiration. This measure mitigates stranded asset risk.
- **Load ramp schedules stage load** increases over time with defined milestones. This measure prevents premature buildout before load materializes.

Financial Security Requirements

- **Upfront deposits** require customers to post refundable deposits tied to projected revenue or infrastructure investment. This measure protects against default risk.
- **Credit and collateral requirements** to incorporate risk symmetry, reduce stranded asset risk and ensure long-term financial viability.

Direct Cost Assignment

- **Contribution in aid of construction (CIAC)** involves customers paying upfront for dedicated facilities (substations, lines, transformers). This measure prevents socialization of customer-specific infrastructure. CIAC payments also act as private grid investments that benefit the broader community, rather than just managing liability.
- **Line extension policies** assign costs beyond defined allowances directly to the customer. This measure limits cost spillover to existing customers.
- **Refund mechanisms for shared use** allow cost sharing to be recalibrated if infrastructure later benefits other customers, preserving fairness over time.

Operational Risk Controls

- **Interruptible or non-Firm service options** allow utilities to curtail load during system stress for customers that opt in. This measure reduces need for new peaking capacity.
- **Demand response participation requirements** encourage or require flexibility during peak events. This measure mitigates capacity-driven infrastructure build.
- **Behind-the-meter generation** involves the loads using on-site generation to manage peak exposure. This measure reduces stress on bulk system.

Planning and Allocation Safeguards

- **Frequent cost-of-service updates** shorten intervals between rate cases or update allocation factors more frequently. This measure reduces regulatory lag under rapid load growth.
- **Separate large load rate classes** isolate risk and cost responsibility within a defined class. This measure prevents cross-subsidization.

Transmission and Interconnection Protections

- **Network upgrade cost assignments** ensure that a customer pays for transmission upgrades triggered by its load. This measure avoids socialization of load-driven upgrades.
- **Queue reform and project readiness requirements** require financial commitments before advancing interconnection. This measure filters speculative projects and reduces stranded risk.

Moreover, this commitment to prevent cost shifting and mitigate risk is held by data center customers as well, with many public pledges to pay their fair share of costs. These commitments have ranged from individual companies announcing their own initiatives to prevent electricity price increases and deliver community benefits to working directly with utilities to fund new infrastructure and community programs to signing the Ratepayer Protection Pledge.

Addressing Common Cost-Shifting Concerns

Recent commentary has raised concerns that rapid data center growth may shift costs onto existing ratepayers, in particular a study from the Harvard Law School in March 2025.[14] These concerns generally fall into five categories: confidential contracts, transmission cost allocation, stranded asset risk, allocator mechanics under reduced load, and co-location with existing generation. Each represents a potential risk pathway but a closer review suggests that these concerns may be overstated and should be evaluated in the context of existing regulatory oversight and customer protections.

1. Confidential or "Secret" Contracts

+ **Concern:** Confidential large load contracts conceal subsidies or wealth transfers.
+ **Context:** While transparency is important, confidentiality does not imply lack of oversight. Large load contracts are typically filed with and reviewed by regulators, even when commercially sensitive terms are protected from public disclosure. Commissions evaluate whether revenues meet or exceed marginal cost, whether embedded cost contributions are sufficient, and whether adequate risk mitigation provisions are included. The existence of confidential terms may limit public visibility, but it does not eliminate regulatory scrutiny.

2. Federal and State Transmission Allocation Differences

+ **Concern:** Differences between federal (FERC/RTO) transmission allocation rules and state-level retail allocation methods may allow transmission costs driven by large loads to impact residential bills.
+ **Context:** Transmission cost allocation is inherently regional and often based on shared-benefit principles rather than strict one-to-one cost causation. This is not unique to data centers; it reflects long-standing market design choices in organized markets.
+ **Concern:** State allocation formulas can become outdated if not updated regularly, particularly under rapid load growth.
+ **Context:** This is a governance issue related to allocator updates and regulatory lag, not proof of systematic current or future cost shifting. Periodic updates to coincident peak allocators and cost-of-service studies are standard tools used to address this risk, and should continue to occur, especially more frequently to match the pace and scale of recent load growth.[15]

3. Stranded Transmission or Generation Investments

+ **Concern:** Utilities could build transmission or generation in anticipation of load growth that does not materialize or underperforms, leaving ratepayers exposed to stranded costs.
+ **Context:** This is a classic forecasting risk and not unique to data centers.[16] The key question is whether utilities require binding financial commitments before making major capital investments. Modern large load tariffs frequently include deposits, collateral, minimum demand obligations, long-term service agreements, and exit fees specifically designed to prevent stranded asset exposure if a project fails to materialize, exits early, or reduces load. Where such provisions are in place, stranded cost risk is significantly reduced.

4. Co-Location with Existing Power Plants

+ **Concern:** Co-locating data centers with existing nuclear plants could withdraw low-cost generation from the organized market, increasing wholesale energy and capacity prices, particularly in PJM.
+ **Context:** This is primarily a wholesale market design issue rather than a retail cost-of-service issue. If generation that previously cleared into the market is instead dedicated to a single co-located load, market supply could tighten. However, such outcomes depend on scale, participation rules, and how market operators and FERC respond. Market rule adjustments, capacity accreditation policies, and interconnection standards fall within federal jurisdiction and are subject to ongoing oversight. The existence of this theoretical pathway does not itself demonstrate retail subsidy but highlights the importance of coordinated federal and state regulation.

While these concerns reflect real structural risks, utilities and regulators have developed and are using a robust toolkit to manage them which is outlined in detail in the next section.

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[14] Martin, E., & Peskoe, A. (2025). *Extracting profits from the public: How utility ratepayers are paying for Big Tech's power* (Report). Harvard Environmental Law Program. https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf

[15] Joint Legislative Audit and Review Commission. (2024). *Virginia data center study: Electric infrastructure and customer rate impacts* (Final report, December 9, 2024). https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

[16] NBC4i. (2025, June 5). *Intel's delay is costing AEP Ohio, but company says price hikes are unrelated*. https://www.nbc4i.com/intel-in-ohio/intels-delay-is-costing-aep-ohio-but-company-says-price-hikes-are-unrelated/

Transmission Cost Allocation

Transmission adds a layer of complexity in large load rate design, given the challenges of allocating costs of shared infrastructure. Most existing transmission cost allocation formulas were not designed to directly attribute the connection costs of large loads to the specific customers that triggered them. One concern is that this causes transmission connection costs to be paid by all ratepayers instead of a clear attribution to new large loads. In practice, it is crucial to determine the two types of transmission interconnection that need to be treated separately:

+ Attributing cost shares to **dedicated facilities** can be relatively straightforward: large customers such as data centers can fund their dedicated interconnection facilities and any distribution upgrades needed to serve their load. Importantly, ratemaking processes need to be designed to ensure such direct attribution, which may require updated regulation.[17]
+ In contrast, **shared transmission** assets serve broader regional reliability and economic needs, making it inherently difficult to isolate the costs attributable to specific users and beneficiaries. This challenge is not new or unique to large loads; transmission cost allocation has long been one of the most contentious issues in rate design and a persistent barrier to grid expansion and modernization.

Transmission costs are typically allocated across users based on capacity and/or energy use consistent with cost-causation principles, and potential benefits. But determining who benefits and to what extent can be challenging and further complicating the long-term nature of these assets and the uncertainty inherent in long-term forecasting. Benefits of new transmission investments can be meaningful, such as avoiding or deferring other infrastructure, reducing operational costs, and improving system reliability and resiliency. The "right" cost allocation depends on several factors and will vary by jurisdiction. Some key principles and considerations to help promote fair allocation include:

+ **Build in flexibility:** Recognize that infrastructure initially driven by one or a few large loads may later provide broader system benefits. Consider crediting or refunding costs once wider benefits are demonstrated and quantified.
+ **Ensure transparency and predictability:** Base allocation frameworks on clear, objective metrics to reduce regulatory uncertainty and investment risk.
+ **Balance precision with practicality:** Overly granular methods can become administratively complex and delay needed infrastructure.
+ **Update allocation factors regularly:** Revisit cost allocators as system conditions and load growth evolve to prevent unintended ratepayer impacts.
+ **Plan proactively:** Use long-term integrated system planning to anticipate growth, reliability needs, and clean energy goals, enabling more forward-looking and equitable cost distribution. More transparent planning tools, such as publicly available hosting capacity maps for load,[18] may help guide siting decisions by identifying available infrastructure and directing new load to areas with existing capacity to reduce system costs.[19]

With large load growth increasing both the scale and pace of transmission investment, transmission cost allocation is becoming even more consequential. Thoughtful application of established principles that are grounded in cost causation, transparency, flexibility, and forward-looking planning can help minimize cost shifting while ensuring that needed transmission investments move forward in a timely and responsible manner.

These tools can be effective in managing potential impacts and mitigating risk but many have not yet been fully tested at scale, such as through rate case proceedings, and their effectiveness will ultimately depend on how projected load materializes and system conditions evolve, underscoring the importance of ongoing monitoring over time.

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

[18] See Xcel Energy example: https://mn.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map

[19] Interview with Natalie Mims Frick, Lawrence Berkeley National Laboratory, April 2026

What the Data Shows: Data Center Rate Impacts to Date

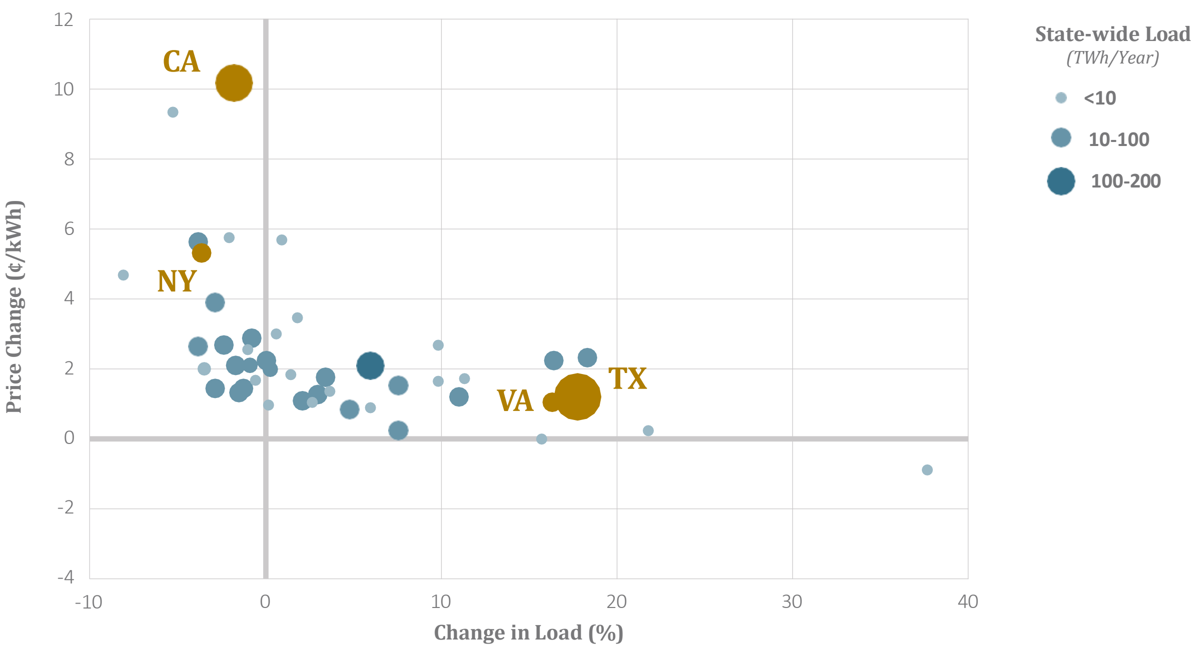
The quantitative literature examining data centers' impact on retail electricity rates is limited, in part due to the recency of the buildout and accordingly limited data.[20] Stakeholder interviews underscored this gap is widely recognized, and that most existing analyses focus on adjacent topics rather than examining direct rate impacts.[21] Several forthcoming analyses commissioned by state entities may expand this evidence base, but the scope, depth, and timing of those assessments remain uncertain.[22] More rigorous and targeted analysis, such as state-by-state event studies that compare outcomes before and after data center growth, is needed, but there are significant analytical challenges given differences in development timing (e.g., in more developed markets such as Northern Virginia vs. more emerging markets), market structures, and regulatory frameworks.[23]

Of the quantitative studies evaluating the impact of data centers on rising electric rates, none have found evidence of historical cost shift to date. Forward-looking analyses highlight potential cost pressures that include valid concerns but are sensitive to assumptions and can be mitigated through effective policy, planning, and rate design.

Review of Historical Studies

The economic consulting firm Bates White recently conducted a study, plotting the change of nominal retail rates against the change in electric load on a state level and found the relationship was not clear.[24] Figure 4 shows states such as California and New York saw the largest price changes (due to wildfire-related costs, grid infrastructure investments, natural gas volatility) but a reduction in load. States such as Texas and Virginia saw the largest increases in load and most data center growth but had some of the smallest price increases.[25] This comparison, however, only assesses correlation between the two outcomes without accounting for any other confounding factors that also affect rates.

Figure 4: *Change in Load vs. Nominal Retail Price Change by State (2019-2024)*



[20] Interview with Lynne Kiesling, Northwestern University, April 2026

[21] Interview with Natalie Mims Frick, Lawrence Berkeley National Laboratory, April 2026

[22] Interview with Natalie Mims Frick, Lawrence Berkeley National Laboratory, April 2026

[23] Interview with Lynne Kiesling, Northwestern University, April 2026

[24] Berry, C. A., Chadha, A., Erickson, G., Malech, S., & Sokol, B. (2026). *Leveraging large loads to improve the U.S. electricity system* (Technical report). Bates White Economic Consulting. https://www.bateswhite.com/media/publication/15039_Leveraging%20Large%20Loads%20to%20Improve%20the%20US%20Electricity%20System%20-%202026.pdf

[25] Lawrence Berkeley National Lab's "Retail electricity price trends and drivers: Data update—2026 edition" found similar results in its analysis examining 2019-2026, which is examined later in this paper.

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.

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[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.

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[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

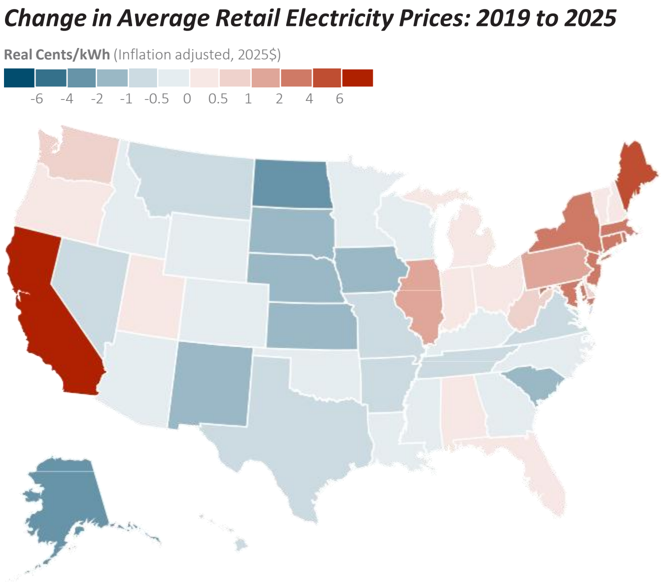
[46] Under its Current Policies case, the model relies more heavily on gas, while under Restored Tax Credits and a stronger Low-Carbon Policy case, more of the incremental demand is met with wind, solar, storage, and other low-carbon resources.

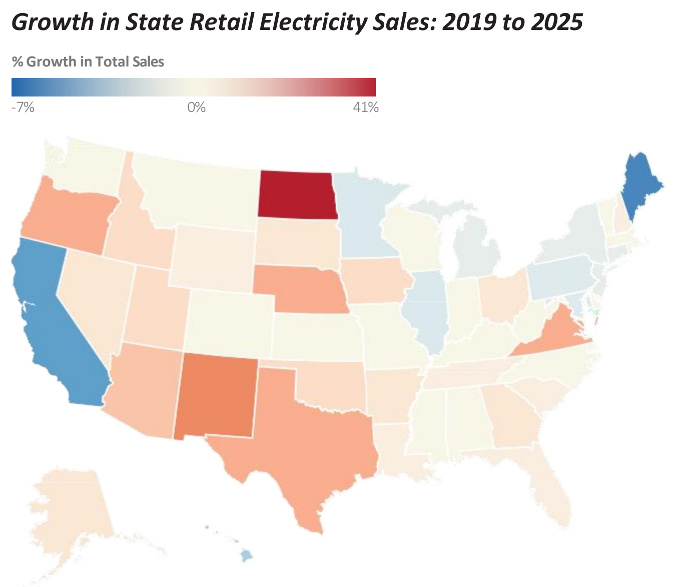
Drivers of Rising Electricity Rates

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]





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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.

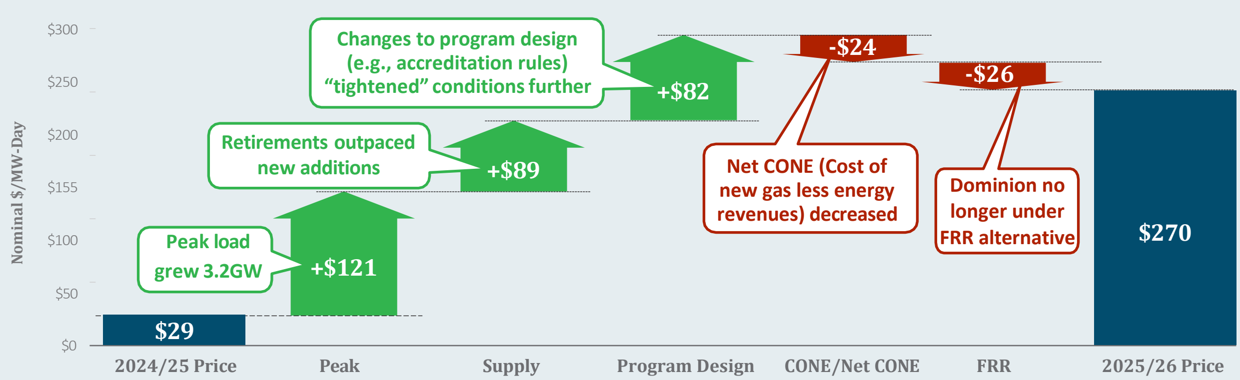
Policy Responses and Customer Risk Protection

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.

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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.

ERCOT Overview

Market Structure and Risk Allocation

ERCOT operates under an energy-only wholesale market with retail competition and unbundled utilities in Texas. Generation is competitive and generators earn revenue through energy market prices. Transmission and distribution infrastructure is owned by regulated Transmission and Distribution Utilities (TDUs), such as Oncor and CenterPoint, whose rates are overseen by the Public Utility Commission of Texas (PUCT). Retail Electric Providers procure power in wholesale markets and sell it to end-use customers.

This structure distributes risk differently than in vertically integrated states. Generation investment risk is borne primarily by private developers and market participants rather than embedded in regulated retail rates. Retail rate exposure depends on procurement arrangements and hedging practices.

For networked infrastructure required to serve large loads, the key risk bearer is the regulated TDU. Transmission and distribution upgrades required to interconnect large customers are identified through formal interconnection studies. Dedicated facilities and many load-triggered upgrades are directly assigned to the connecting customer, reducing the likelihood that customer-specific infrastructure costs are broadly socialized. Financial security requirements and milestone-based construction processes further mitigate stranded asset risk at the infrastructure level.

As a result, the primary risk that data centers pose is to TDUs, within their management of network costs and stranded asset mitigations, and on the ability of retail electric providers to hedge against high prices.

Scale of Growth and Market Trends

Texas has experienced significant projected load growth driven by data centers, electrification, hydrogen fuel production, increased heating and cooling needs due to extreme weather, crypotocurrency mining, and population growth. The Dallas–Fort Worth area in particular has become a major hub for data center development. In 2024, there was 6.5 GW of large load approved to operate in ERCOT.[72]

Despite this growth, recent state-level analyses do not show a clear correlation between load growth and retail rate increases. For example, the LBNL study examining retail electricity price trends found that Texas experienced substantial load growth while maintaining comparatively modest retail price increases relative to regions such as California and the Northeast. This suggests that historical rapid load growth in Texas has not translated into disproportionate retail rate escalation.

In an interview with Dr. Ning Lin of The University of Texas at Austin, she noted that evidence across markets is mixed, and that electricity rate trends are shaped by multiple overlapping factors, making them difficult to attribute to any single driver. She suggested that some observed rate increases may reflect underlying system needs, such as ongoing investments to maintain and upgrade infrastructure, which could put upward pressure on rates even in the absence of new large loads. In Texas, she noted that recent residential rate increases reflect a combination of drivers-transmission and distribution capital investment, post-Winter Storm Uri reliability spending, storm cost recovery, and natural gas fuel-cost volatility - much of which would have been required to maintain reliability and serve population growth independent of incremental data center load. This underscores the importance of defining the appropriate base case and counterfactual for comparison – distinguishing between investments that would have occurred anyway from those driven by incremental demand. She also emphasized that as new large-load demand materializes, the binding policy question shifts from backward attribution toward forward design, specifically, how to allocate the costs of incremental system investments equitably across customer classes, a question regulators in Texas are now actively addressing.[73]

[72] Hodge, T. (2024, October 3). *Data centers and cryptocurrency mining in Texas drive strong power demand growth.* U.S. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=63344

[73] Interview with Dr. Ning Lin, University of Texas at Austin, April 2026

Policy Responses and Customer Risk Protection

In response to broader reliability concerns and future forecasts of substantial load growth,[74] the state has undertaken a series of market reforms and reliability initiatives. Most notably, Senate Bill 6 mandates the PUCT to ensure that large load customers contribute to network upgrades and establishes interconnection standards for large load customers which will minimize stranded costs and maintain system reliability. Notable features of Senate Bill 6 include:[75]

- Require disclosure of duplicative interconnection requests within Texas
- Require demonstration of site control and financial commitment
- Disclose on-site back-up generation
- Require that large load customers connecting after December 31, 2025 allow load curtailment during emergency conditions

Going forward, these reforms will help mitigate the risks of cost shifting and electricity impacts from data center growth.

Alongside these policy efforts, more coordinated, data-driven and stakeholder-focused planning approaches are also emerging, such as COMPASS initiative – a multi-disciplinary research consortium based at the Bureau of Economic Geology at The University of Texas at Austin.[76] In an interview, Dr. Ning Lin, principal investigator of COMPASS, described how the effort integrates localized analysis of site suitability, water and cooling, grid and on-site power, permitting, and community engagement with active cross-stakeholder coordination. This framework brings together communities, developers, and public agencies to build a shared understanding of project feasibility and impacts. Approaches like this can help inform planning and improve transparency, while recognizing that their applicability can vary by context.[77]

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[74] Electric Reliability Council of Texas. (n.d.). *Load forecast.* ERCOT. https://www.ercot.com/gridinfo/load/forecast

[75] Texas Legislature. (2025). *Senate Bill 6: Relating to the planning for, interconnection and operation of, and costs related to providing service for certain electrical loads and to the generation of electric power by a water supply or sewer service corporation* (Enrolled bill). LegiScan. https://legiscan.com/TX/text/SB6/id/3248460

[76] Collaborative Optimization & Management of Power Allocation – Surface & Subsurface Strategies https://compass.beg.utexas.edu/

[77] Interview with Dr. Ning Lin, University of Texas at Austin, April 2026

Georgia Overview

Market Structure and Risk Allocation

Georgia's electricity sector operates under a vertically integrated regulatory model. The largest utility, Georgia Power, owns generation, transmission, and distribution and recovers the cost through retail rates approved by the Georgia Public Service Commission (PSC). Georgia Power's scale makes it the primary focus for statewide planning and cost allocation decisions, despite other service providers. In a vertically integrated utility, the primary policy question is not competition or price discovery but regulatory cost recovery and fair risk allocation.

The Territorial Electric Service Act in Georgia defines service territories, including limited retail choice for certain large manufacturing or commercial customers, which shapes how large customers like data centers are assigned to utilities and prevents duplication of infrastructure – an important constraint on where risk is assigned. In a vertically integrated utility model, utilities can petition regulators to include cost in rates base, and the PSC scrutinizes long-term forecasts and investment plans to assess prudence.

Scale of Growth and Market Trends

Atlanta is quickly emerging as one of the fastest-growing data center markets in North America. As per CBRE's 2025 data, Atlanta concluded 2025 with approximately 1,459 MW of total data center inventory, reflecting an annual increase of nearly 459 MW and solidifying its position as the second-largest U.S. market behind Northern Virginia. Atlanta's under-construction data center pipeline totaled approximately 2,076 MW, as of year-end 2025.[78] Continued hyperscale, cloud, and AI-driven demand has sustained strong colocation leasing activity and contributed to tightening market capacity. This rise is mainly driven by both traditional colocation customers and tenants seeking GPU-as-a-service (GPUaaS) deployments.[79] A 2025 PSC-approved IRP outlines nearly 9,885 MW of new generation capacity largely to meet projected demand increases, driven mainly by data centers.[80]

Policy Responses and Customer Risk Protection

The Georgia PSC approved new rules in January 2025 that modify how large load customers (larger than 100 MW) are billed and contracted by Georgia Power.[81] This requires large loads like data centers to pay certain site-specific and upstream costs for generation, transmission, and distribution during construction, enforce minimum billing periods, extend contract lengths (from 5-year typical terms to 15-years), and subject each new large load contract to PSC review. The intention of this rule is to help ensure that incumbent customers are not left paying for infrastructure built for high-usage customers that might fail to materialize or that might depart early.

These protections address the risk pathways to retail customers by shifting part of the incremental and stranded cost risk to the data center customers themselves. Staging cost responsibility and enforcing minimum billing reduces the likelihood that investments are stranded mid-deployment. Longer contract terms mitigate the 'walk-away' risk if data center operations are disrupted. Regulatory review of new contracts allows transparency and oversight into long-term cost commitments.

Moreover, the PSC's ruling to keep base retail rates frozen through at least 2028 provides near-term pricing stability for ratepayers, even as the underlying cost pressures from growth continue. [82] While this freeze does not directly protect retail consumers from all cost pathways, it demonstrates an intentional approach to manage timing and exposure of retail impacts.

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[78] CBRE. (2026, March 4). *Atlanta emerges as one of North America's fastest-growing data center hubs.* CBRE. https://www.cbre.com/press-releases/atlanta-emerges-as-one-of-north-americas-fastest-growing-data-center-hubs

[79] GPUaaS is a cloud-based service that provides users with on-demand access to high-performance graphics processing units (GPUs).

[80] Herrera, M. C., Morton, L. S., & Rueger, J. (2026, January 7). *Georgia Public Service Commission approves Georgia Power's major generation expansion to support data center load.* Mondaq (Oil, Gas & Electricity). https://www.mondaq.com/unitedstates/oil-gas-electricity/1727972/georgia-public-service-commission-approves-georgia-powers-major-generation-expansion-to-support-data-center-load

[81] Georgia Public Service Commission. (2025, January 23). *Media advisory: Data centers rule* (PDF). https://psc.ga.gov/site/assets/files/8617/media_advisory_data_centers_rule_1-23-2025.pdf

[82] Georgia Power. (2025, January 9). *Georgia PSC approves plan to freeze base rates through 2028* (Press release). https://www.georgiapower.com/news-hub/press-releases/georgia-psc-approves-plan-to-freeze-base-rates-through-2028.html

Arizona Overview

Arizona's electric sector is experiencing a period of accelerated load growth driven mostly by data centers concentrated in the Phoenix metropolitan area. As a vertically integrated, regulated market, Arizona differs fundamentally from competitive wholesale markets: utilities are responsible for long-term capacity planning and infrastructure investment, with costs recovered through regulated rates. This structure enables coordinated planning but places increased importance on how incremental costs associated with new large loads are allocated between new and existing customers.

Market Structure and Risk Allocation

Arizona's electricity system is served primarily by vertically integrated utilities, including Arizona Public Service (APS), Tucson Electric Power (TEP), and Salt River Project (SRP). The Arizona Corporation Commission (ACC) regulates the investor-owned utilities, APS and TEP, including oversight of integrated resource plans (IRPs), rate design, and cost recovery.[83]

Under this model, utilities plan and procure resources to meet forecasted demand growth, including generation, storage, and network infrastructure. Investment risk, particularly the risk of overbuilding or underutilizing infrastructure is largely socialized through rates and can be mitigated through specific rate design or contractual mechanisms. As a result, periods of rapid and uncertain load growth increase regulatory focus on cost causation, risk mitigation and the potential for cross-subsidization.

Scale of Growth and Market Trends

Public utility disclosures indicate a material shift in load forecasts: APS has projected sustained retail sales growth of approximately 4-6% annually in the near term.[84] While data centers currently represent a modest share of total system peak, utilities have identified a substantial pipeline of prospective large load interconnections.[85]

The Phoenix region has emerged as a leading North American data center market. Industry reporting indicates very low vacancy rates (approximately 2-3%) and a significant development pipeline, suggesting continued buildout and demand for electricity infrastructure.[86] Unlike more diffuse forms of load growth, data center development tends to require substantial, location-specific investments in transmission and distribution infrastructure, as well as firm capacity to meet high load factors.

Utilities have responded by accelerating procurement and infrastructure development. APS has indicated plans for significant near-term additions of generation and storage resources, including a large share of carbon-free capacity additions.[87] This reflects a broader trend in which load growth is advancing the timing of resource needs relative to historical expectations.

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[83] Arizona Corporation Commission (ACC), *Integrated Resource Planning Workshop Highlights: How Arizona Regulated Utilities Plan to Power Arizona's Future, 2024.* https://azcc.gov/news/home/2024/08/01/integrated-resource-planning-workshop-highlights---how-arizona-regulated-utilities-plan-to-power-arizona-s-future

[84] Pinnacle West Capital Corporation, *2024 Full Year and Q4 Earnings Release, February 2025; APS, statements on projected retail sales growth and capacity expansion plans.* https://www.pinnaclewest.com/newsroom/company-news/news-release-details/2025/Pinnacle-West-Reports-2024-Full-Year-and-Fourth-Quarter-Results/default.aspx

[85] Arizona Public Service (APS), *Data Centers: How We're Protecting Customers While Planning for Big Energy Needs, 2025.* https://www.aps.com/en/About/Our-Company/Newsroom/Articles/Data_Centers_How_Were_Protecting_Customers_While_Planning-for_Big_Energy_Needs

[86] JLL, *North America Data Center Report, 2025* (noting ~2.3% vacancy and strong Phoenix market growth). https://www.jll.com/en-us/insights/market-dynamics/north-america-data-centers

[87] APS 7,*300 MW procurement* (2024). https://www.tdworld.com/renewables/news/55245162/aps-signs-agreements-to-add-about-7300-mw-of-renewable-power-battery-energy-storage-and-natural-gas-to-energy-mix

Policy Responses and Customer Risk Protection

Regulatory attention in Arizona has increasingly focused on ensuring that the costs associated with large load growth are allocated in a manner consistent with cost causation principles. In 2025, the ACC initiated a proceeding to examine data center rate classifications and related policy questions, including protections for existing customers from cost shifts.[88]

Utility rate design and interconnection policies are evolving in parallel. APS has proposed new rate structures for high-load-factor customers, including data centers, intended to better align revenues with cost of service and mitigate cross-subsidization. The company has also proposed significantly higher revenue requirements for its extra-high-load-factor class relative to residential customers and emphasized the use of long-term service agreements and minimum demand commitments.[89]

SRP has implemented similar mechanisms through its own board-approved pricing process, including a Large Customer Integration Process as well as an updated E-67 commercial and industrial price plan, requiring upfront payment for infrastructure and minimum billing provisions tied to forecast demand (e.g., 80% minimum demand thresholds for ≥20 MW customers).[90] These approaches aim to reduce the risk that speculative or delayed projects result in stranded investments borne by existing customers.

Market Summary

Arizona's experience highlights a broader dynamic facing regulated utilities: large load growth can improve system utilization and support economic development, but also introduces planning uncertainty and the potential for cost misallocation. In contrast to competitive markets, where generators bear a greater share of market risk, Arizona's framework necessitates explicit regulatory and contractual mechanisms to assign risk appropriately.

The current policy trajectory suggests a shift toward more granular cost allocation for large load customers, particularly data centers, alongside increased use of contractual safeguards. The effectiveness of these measures will depend on the ACC's ability to balance economic development objectives with rate stability and equitable treatment of existing customers as the scale and pace of data center development continue to evolve.

88 Arizona Corporation Commission, *ACC Opens Docket to Examine Data Center Development and Customer Protections* (Docket No. E-00000A-25-0069), April 2025. https://edocket.azcc.gov/search/docket-search/item-detail/29509

89 Arizona Public Service (APS), *2025 General Rate Case Public Notice and Filing Materials, 2025.* https://www.aps.com/en/Utility/Regulatory-and-Legal/Rate-case

90 Salt River Project (SRP), *Data Center Facts and Large Customer Integration Process Overview, 2025.* https://www.srpnet.com/about/data-center-facts

Missouri Overview

Missouri's power sector is beginning to experience data center-driven load growth as a distinct planning issue, and is more of an emerging market compared to other regions such as Arizona. Missouri operates under a regulated, vertically integrated framework, with investor-owned utilities including Ameren Missouri and Evergy serving retail customers under Missouri Public Service Commission (PSC) oversight. At the same time, utilities participate in regional wholesale markets—Ameren in MISO and Evergy in SPP—introducing additional planning and reliability considerations.[91,92]

Market Structure and Risk Allocation

In Missouri's structure, utilities remain responsible for load forecasting, resource procurement, and infrastructure investment, with costs generally recovered through regulated rates. As a result, the primary issue raised by large data center development is cost allocation: how to ensure that investments made to serve new, high-load customers do not shift risk onto existing ratepayers. This has elevated cost causation and stranded-cost risk as central regulatory concerns.

Scale of Growth and Market Trends

Recent filings indicate a material shift in expected large load growth. Ameren Missouri reported that its 2023 IRP assumed incremental economic development load rising from 40 MW in 2025 to 220 MW by 2031, but by 2025 had observed "significant growth" in data center interest, prompting updates to its preferred resource plan.[93] The company has since indicated planning for up to 2 GW of additional demand by 2032.[94] Evergy has similarly cited record economic development and growing load as drivers of additional resource needs.[95]

This trend is increasingly supported by identifiable projects. Google announced a $1 billion data center in the Kansas City area, paired with approximately 400 MW of new carbon-free energy.[96] In addition, large-scale proposals such as a $100 billion multi-phase data center campus in the Kansas City Northland highlight the scale of potential future demand.[97] State-level materials likewise identify data centers as an emerging driver of electricity consumption and infrastructure expansion.[98]

This growth has coincided with rising electric rates in Evergy MO, including a requested rate increase of 14.9% driven by a broader utility investment cycle in new generation, as the utility is already in a build cycle, and compounded by supply chain and labor cost pressures.[99] Data center load has already contributed $20 million in incremental revenue, which has been used to reduce the overall revenue requirement.[100]

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91 Midcontinent Independent System Operator (MISO), "Members," https://www.misoenergy.org/about/who-we-are/members/

92 SPP Planning, https://www.spp.org/engineering/transmission-planning/

93 Ameren Missouri, *2025 Preferred Resource Plan.* https://s21.q4cdn.com/448935352/files/doc_downloads/2025/03/25-02-28-2025-Change-in-Preferred-Plan-Report-Public.pdf

94 Ameren Corporation, "State regulators approve Ameren Missouri's plan...," Nov. 24, 2025. https://ameren.mediaroom.com/2025-11-24-State-regulators-approve-Ameren-Missouris-plan-to-reliably-serve-new-large-businesses,-boosting-states-economy-while-safeguarding-consumers

95 Evergy, "Evergy plan maintains lowest-cost approach...," Apr. 1, 2024. https://investors.evergy.com/news-releases/news-release-details/evergy-plan-maintains-lowest-cost-approach-meeting-growing

96 Missouri Partnership, "Google Announces $1 Billion Data Center in Kansas City, Missouri," Mar. 20, 2024. https://missouripartnership.com/google-announces-1-billion-data-center-in-kansas-city-missouri/

97 Port KC, "$100 Billion Data Center Development...," Aug. 26, 2025. https://portkc.com/100-billion-data-center-development-to-bring-infrastructure-investment-and-jobs-to-the-northland/

98 Missouri Department of Natural Resources, "Trends in Energy Demand: Data Centers," May 2025. https://dnr.mo.gov/document/trends-energy-demand-data-centers-presentation-modnr-may-14-2025

99 Interview with Kevin Gunn, Evergy, April 2026

100 Interview with Kevin Gunn, Evergy, April 2026

Policy Responses and Customer Risk Protection

Missouri has moved relatively quickly to establish large load-specific tariffs and contractual protections. In November 2025, the Missouri PSC approved Evergy's large load service plan for customers with at least 75 MW of peak demand, including minimum 12-year contract terms and other provisions aimed at limiting cost shifts.[101] In an interview with Kevin Gunn, Evergy's Vice President of Regulatory and Government Affairs and former Missouri PSC Chairman, the development of this tariff was highlighted as a useful case study in aligning diverse stakeholder interest; the process included robust stakeholder engagement throughout, with regulators ultimately finding it provides strong protections and large load customers viewing the framework as workable.[102] In his view, the four critical elements of large load rate design, as reflected in Evergy's tariff, are a premium pricing structure, financial requirements, minimum contract lengths, and minimum bill provisions, all intended to ensure cost recovery and reduce risk to other ratepayers. Moreover, rate design can be a tool not only to protect ratepayers but also to capture the potential system benefits of large loads, including putting downward pressure on residential rates when paired with appropriate generation development.

Looking ahead, Mr. Gunn acknowledged that the tariff may not be perfect, noting uncertainty about how future conditions will evolve. However, he emphasized that embedding these provisions in a tariff framework allows for flexibility to adapt to changing market conditions, with ongoing monitoring of pricing and riders and making adjustments as needed.[103]

The PSC subsequently approved a large load rate structure for Ameren Missouri, also emphasizing customer protections alongside economic development.[104] These frameworks require long-term commitments and greater cost responsibility from large load customers, reflecting a proactive approach to mitigating stranded-cost risk before large-scale buildout fully materializes.

Market Summary

Missouri appears earlier in the data center growth cycle than leading markets but is comparatively advanced in formalizing risk-allocation mechanisms. The state's approach places emphasis on contractual safeguards and cost-causation-based rate design. The key challenge going forward will be accommodating large load growth while maintaining rate stability and avoiding cross-subsidization of infrastructure investments.

[101] Missouri Public Service Commission, "PSC Approves Evergy Large Load Power Service Plan...," Nov. 2025 (Case No. EO-2025-0154). https://psc.mo.gov/Electric/PSC_Approves_Evergy_Large_Load_Power_Service_Plan_with_Customer_Protections--pr-26-38

[102] Interview with Kevin Gunn, Evergy, April 2026

[103] Interview with Kevin Gunn, Evergy, April 2026

[104] Missouri Public Service Commission, "PSC Approves Ameren Missouri Large Load Power Rate Plan...," Nov. 24, 2025. https://psc.mo.gov/Electric/PSC_Approves_Ameren_Missouri_Large_Load_Power_Rate_Plan_with_Customer_Protections--pr-26-40

Conclusion

The quantitative analyses conducted to date show no historical evidence of cost shifting from data centers to other utility customers. In some cases, data centers may provide benefits for other customers by creating downward pressure on rates. While load growth has coincided with rising electricity rates in some regions, the relationship between the two is unclear. More broadly, the quantitative literature indicates that there are multiple factors that have driven recent rate increases such as inflation, fuel volatility, grid investments, and wholesale market dynamics – rather than load growth. And even where costs have increased, the ultimate impact on customers depends on how those costs are allocated.

Forward-looking studies highlight risks that warrant a proactive approach to mitigate short-term wholesale price pressures, better align with state policy goals, and address regulatory gaps in cost allocation. The conversation should therefore shift beyond generalized claims and instead focus on a more precise and actionable question to ensure this outcome moving forward: what tariff structures, planning paradigms, and cost-allocation practices ensure that data centers bear their full costs as the system evolves and are aligned with state policy objectives?

A framework for responsible growth should include the following actions:

- **Leverage Tailored Large Load Tariffs.** Modern large load tariffs demonstrate that risk is not only identifiable but also manageable. When properly designed, these tariffs can align cost causation and mitigate risk, protecting other customers without constraining economic growth. Utilities and regulators therefore do not face a binary choice between attracting investment and safeguarding ratepayers; disciplined planning and tailored tariff design can achieve both. Critically, however, a one-size-fits-all approach will not work. Effective tariff design should reflect market-specific conditions and be grounded in transparent, evidence-driven analysis, not arbitrary thresholds.
- **Improve Transmission and Interconnection Cost Assignment.** Dedicated facilities and directly attributable upgrades should be assigned as transparently as possible to the customers that cause them. For shared network upgrades, regulators should apply cost-allocation principles that balance fairness, practicality, and evolving system benefits, while updating frameworks as load patterns and infrastructure use change.
- **Align Cost Allocation with the Pace of Load Growth.** Regulatory lag is a key source of potential misalignment, and more frequent cost-of-service updates can ensure that cost responsibility evolves alongside system dynamics. The recent expansion of large load tariffs shows that regulatory frameworks are already adapting and they should continue to do so.
- **Strengthen Planning and Forecasting Processes.** Given the inherent uncertainty in forecast plus trends in speculative load, utilities and regulators should rely on scenario-based planning, stronger customer financial commitments, and clearer project-readiness standards. This reduces the risk of overbuild, stranded infrastructure, and unnecessary customer exposure.
- **Use Innovative Policies to Integrate Load More Cost-Effectively.** Integrating large loads cost-effectively requires aligning them with system capabilities, planning, and policy goals. This includes leveraging load flexibility and "bring your own generation" models, while ensuring tariffs and programs reward large customers for reducing system costs. Moreover, utilities can support by providing more transparency on available capacity and upgrade timelines to improve siting efficiency and avoid unnecessary costs. On the supply side, structural policy changes are needed to support timely expansion, particularly by addressing permitting delays and supply chain constraints, including shortages of critical equipment like transformers. Taken together, these approaches can reduce system costs while supporting affordability, reliability, and decarbonization objectives.
- **Expand Monitoring and Targeted Analysis.** The evidence base remains limited, especially on long-term retail rate impacts and the real-world performance of new tariff protections. Regulators, utilities, researchers, and policymakers should continue to evaluate outcomes over time so that future decisions are informed by measured experience rather than assumptions or generalized claims.

Taken together, these actions point to a clear path forward as electricity systems enter a new phase of sustained load growth. With thoughtful market-specific and evidence-based approaches, policymakers can support continued growth while ensuring costs are borne by those who drive them while protecting other customers.

Appendix

A.1. Overview of Quantitative Studies Reviewed

Study Authors and Name	Year	Forward or Backward Looking	Study Type	Geographic Scope	Relevance to Whitepaper	Limitations
Bates White, "Leveraging large loads to improve the U.S. electricity system," February 2026	2026	Backward-looking	Quantitative	United States	Relevant for assessing the relationship between load growth and retail electricity prices across states, showing no clear relationship between data centers and rate increases.	Relies on high-level state comparisons and correlation analysis; does not establish causality or isolate data center-specific impacts.
EPRI, "Powering Intelligence 2026: Updated Scenarios of U.S. Data Center Electricity Use and Power Strategies," February 2026.	2026	Forward-looking	Quantitative	United States (mainland state-level analysis)	Highly relevant for whitepaper discussion of load growth, peak demand, state concentration, and supply strategies.	Relies heavily on project pipeline and public announcement data, which the report itself notes may overstate or misstate realizable development. Findings depend on assumptions about PUE, utilization, ramp-up, and completion rates, and some projected sites may not be built as announced.
Federal Reserve Bank of Dallas, "Data center boom expected to raise electricity component of PCE inflation," March 2026.	2026	Forward-looking	Quantitative, comprehensive wholesale electricity price model (using hourly unit commitment) and scenario analysis	United States	Relevant for discussing downstream electricity price and inflation impacts of data center load growth.	Focuses on inflation and retail electricity prices rather than broader system planning or siting issues affected by transmission connection cost. Results are scenario-based and sensitive to assumptions about data center build-out, utilization, renewables growth, specific customer allocation of added cost and pass-through from wholesale to retail prices. An implicit keeping the status quo regulations assumption might overstate actual wholesale price and inflationary effect of DCs as these costs could be fully allocated to new large loads, while an absence of accounting for grid connection and upgrade costs may understate their impact on consumer retail prices and inflation.
Georgia Institute of Technology, "The Local Economic Effects of Data Center Entry," March 2026.	2026	Backward-looking	Quantitative econometric study using a staggered difference-in-differences framework	United States, county-level analysis	Relevant as one of the few recent econometric studies that tests whether data center entry is associated with changes in local electricity prices. The paper finds early evidence that data center entry may place upward pressure on electricity prices in some lower-spillover county settings, while also emphasizing the difficulty of identifying broader long-term rate impacts.	The paper's main contribution is broader local economic effects, not electricity prices specifically. Its electricity-price analysis is constrained by utility service territories spanning multiple counties, which makes clean causal identification difficult and can weaken the measured effect. The authors only detect positive price effects in lower-spillover settings pointing to smaller utility territories, while the full-sample result is noisy. In addition, the median first-entry facility in the sample is relatively small—10 MW nameplate, or roughly 1.2% of the median serving utility's annual load—so the study is better viewed as early indicative evidence than as a definitive estimate of the rate effects of today's large load clusters.

Study Authors and Name	Year	Forward or Backward Looking	Study Type	Geographic Scope	Relevance to Whitepaper	Limitations
Union of Concerned Scientists, “Data Center Power Play: How Clean Energy Can Meet Rising Electricity Demand While Delivering Climate and Health Benefits,” January 2026.	2026	Forward-looking	Quantitative	United States	Relevant for policy, clean energy, emissions, health, and ratepayer implications of data center demand growth.	More policy-advocacy oriented than a neutral technical forecasting study. Conclusions depend on modeled policy scenarios and assumptions about future tax credits, carbon standards, and data center demand growth. Less focused on facility-level operational realities than on system-wide policy outcomes.
Analysis of the 2026/2027 RPM Base Residual Auction Part A, Independent Market Monitor for PJM	2025	Backward-looking	Quantitative	PJM	Relevant for discussing the impact of data center load on PJM capacity prices, in the context of tight supply conditions.	The report focusses on the impacts of data center load in the context of tight supply but doesn’t discuss the factors that to led to tight supply conditions, such as changes to the accreditation of fossil fuels.
Charles River Associates, “Retail rate trends in the US,” September 2025	2025	Backward-looking	Quantitative	United States	Relevant for examining historical electricity price increases and case studies for regions that have experienced price increases	While the study identified specific variables that may have caused higher electricity prices, they do not quantitatively examine the causal relationship between these variables and electricity prices.
Energy and Environmental Economics, Inc., "Tailored for scale: Designing electric rates and tariffs for large loads,” December 2025	2025	Both	Quantitative	4 utilities in CA, OR, VA, MS	Examines whether data centers pay their incremental cost to serve across multiple utilities, finding neutral to positive impacts and potential rate benefits for other customers.	Based on a limited set of case studies and assumptions about marginal cost; results may not fully capture system-wide or long-term impacts under different growth scenarios.
Lawrence Berkeley National Laboratory, “Factors influencing recent trends in retail electricity prices in the United States,” October 2025	2025	Backward-looking	Quantitative	United States	Relevant for examining historical electricity price increases and variables that have a statistical correlation with electricity price increases	The study only looked at a certain number of variables and did not quantitatively examine the causal relationship between statistically significant variables and electricity prices.
Union of Concerned Scientists, “Connection Costs: Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid,” September 2025.	2025	Backward-looking / current-state	Policy brief / qualitative with quantitative evidence	PJM states (Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia)	Relevant to the white paper’s discussion of transmission-level interconnection, cost allocation, and potential ratepayer exposure when very large data centers connect directly to the high-voltage grid. It is particularly useful for explaining how split oversight between utilities, state PUCs, and FERC can create transparency gaps and weaken cost-causation principles.	The study is narrower than national forecasting or system-planning analyses. It focuses on PJM planning filings and a specific transmission cost-allocation issue in seven PJM states, so it should not be read as a national estimate of consumer impacts, but as a blueprint for a regulatory gap that may apply across many US states. Its findings are best understood as evidence of a potential transparency and incentive problem in how connection costs are tracked and assigned, rather than as a final audited measure of net ratepayer harm.
Joint Legislative Audit and Review Commission, “Virginia data center study: Electric infrastructure and customer rate impacts,” December 2024	2024	Backward-looking	Quantitative	Virginia	Evaluates data center impacts in Virginia and finds no evidence of historical or current cost shifting under existing regulatory frameworks.	Focused on a single state and current regulatory structures.

A.2. Select Large Load Tariffs (2018-2026)

Year	Utility	Name	State	Minimum Load Factor	Long Term Contract Years	Includes Minimum Monthly Demand Payments	Includes Contribution in Aid of Construction (CIAC)	Exit Fee Time Period (Months)
2026	Black Hills Power	Economic Flexible Load Service (EFLS)	SD	-	2	Yes	Yes	-
2026	Commonwealth Edison	TSA with Aligned	IL	-	-	Yes	No	-
2026	Commonwealth Edison	TSA with Equinix	IL	-	-	Yes	No	-
2026	Commonwealth Edison	TSA with Grundy County Power	IL	-	-	Yes	No	-
2026	Commonwealth Edison	TSA with Karis Critical, LLC	IL	-	-	Yes	No	-
2026	Commonwealth Edison	TSA with Monarch	IL	-	-	Yes	No	-
2026	Commonwealth Edison	TSA with PowerHouse	IL	-	-	Yes	No	-
2026	Commonwealth Edison	TSA with QTS Investment	IL	-	-	Yes	No	-
2026	Entergy Louisiana	ESA with Meta	LA	-	15	Yes	Yes	Remaining months
2026	Evergy Missouri West, Evergy Metro	Large Load Power Service	MO	-	12	Yes	Yes	Greater of 12 months or remaining months
2026	Florida Power and Light	Large Load Contract Service-1 (LLCS-1)	FL	85%	20	Yes	Yes	-
2026	Florida Power and Light	Large Load Contract Service-2 (LLCS-2)	FL	85%	20	Yes	Yes	-
2026	PacifiCorp	Schedule 401	OR	-	10	Yes	No	-
2025	AEP Ohio	Schedule DCT (Data Center Tariff)	OH	85%	8	Yes	Yes	36
2025	Arkansas Electric Cooperative Corporation	Transmission Extension of Facilities Tariff (TEOF)	AR	-	5	Yes	Yes	-
2025	DTE Energy	Special Contract with Green Chile Ventures LLC	MI	80%	19	Yes	No	-
2025	Duke Energy Carolinas	Schedule HLF: High Load Factor	NC	-	1	Yes	No	-
2025	East Kentucky Power Cooperative	Data Center Power (DCP) Tariff	KY	60%	Custom	Yes	No	-
2025	El Paso Electric	Economic Development Rate Riders for a New Data Center-- Rate Schedule No. 33A: Large Economic Development Rate	TX	-	5	Yes	No	-
2025	El Paso Electric	Economic Development Rate Riders for a New Data Center-- Rate Schedule No. 33B: Medium Economic Development Rate	TX	-	5	Yes	No	-

Year	Utility	Name	State	Minimum Load Factor	Long Term Contract Years	Includes Minimum Monthly Demand Payments	Includes Contribution in Aid of Construction (CIAC)	Exit Fee Time Period (Months)
2025	Entergy Arkansas	Special Rate Customer Contract	AR	-	-	Yes	No	-
2025	Evergy Kansas Metro, Evergy Kansas South, Evergy Kansas Central	Large Load Power Service	KS	-	15	Yes	Yes	Greater of 12 months or remaining months
2025	Georgia Power	Large Load Contracting Framework	GA	-	-	Yes	-	Remaining months
2025	Kentucky Utilities Company	Extremely High Load Factor (EHLF) Service	KY	85%	15	Yes	-	-
2025	Louisville Gas & Electric	Extremely High Load Factor (EHLF) Service	KY	85%	15	Yes	-	-
2025	Mecklenburg Electric Cooperative	Schedule LPS-U (Large Power Service)	VA	-	-	Yes	Yes	-
2025	NV Energy	Clean Transition Tariff	NV	-	15	No	No	-
2025	Pacific Gas and Electric	Electric Transmission Service Facilities for STACK Infrastructure	CA	85%	-	No	No	-
2025	Tucson Electric Power	Electric Service Agreement with Humphrey's Peak Power, LLC	AZ	-	10	Yes	No	36
2025	Union Electric Company	Large Load Customer Service (LLCS)	MO	75%	15	Yes	Yes	Lesser of five years or remaining months
2023	Idaho Power	Schedule 33	ID	-	-	Yes	No	-
2023	Montana-Dakota Utilities	High Density Contracted Demand Response Rate 45	SD	85%	3	No	Yes	-
2023	Northern States Power Company – Minnesota	Competitive Rate Rider Tariff	MN	-	10	Yes	No	-
2022	Entergy Arkansas	Large Power High Load Density Service (LPHLDS)	AR	10%	1	Yes	Yes	-
2022	Evergy Missouri West, Evergy Metro	Special High-Load Factor Market Rate Schedule (MKT)	MO	85%	-	Yes	No	-
2022	Idaho Power	Schedule 20	ID	-	-	Yes	Yes	-
2022	Otter Tail Power Company	Super Large General Service	MN	80%	5	No	No	-
2018	New York Municipal Power Agency	Rider A - Rates and Charges for High Density Load ("HDL") Service	NY	-	-	Yes	Yes	-