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.

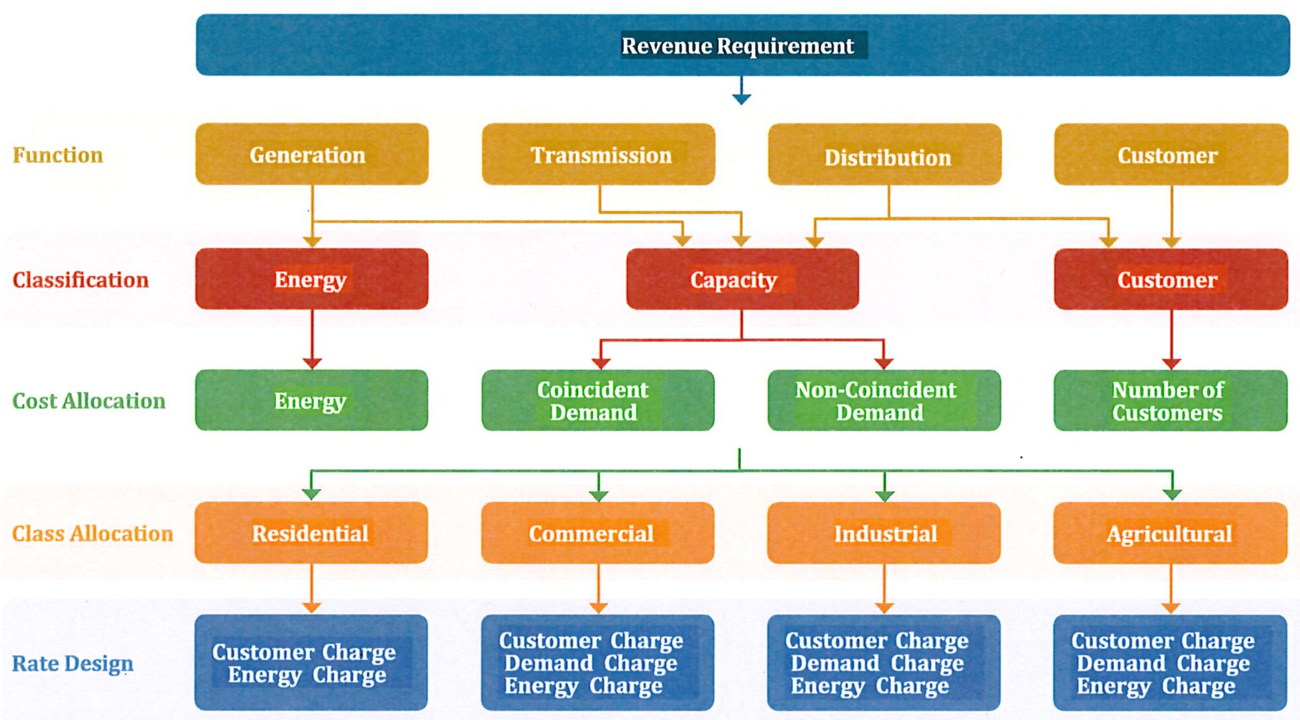
Primer: Retail Rate Design and Cost Allocation

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]



[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.

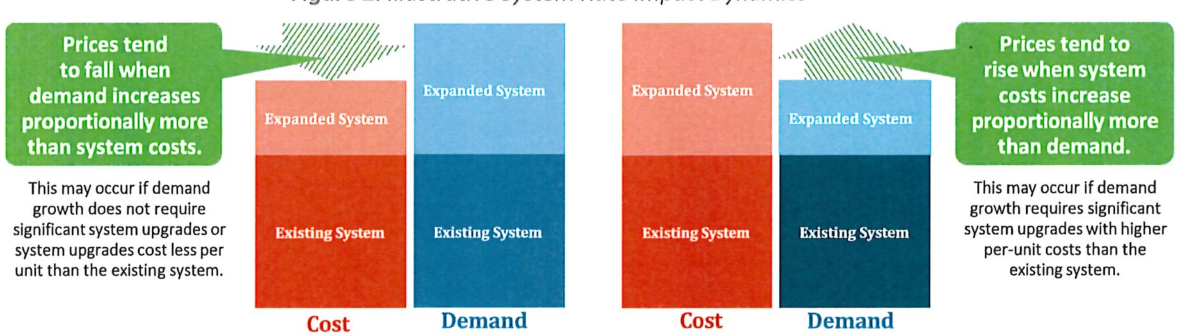
Why Rates Rise (or Fall), and What Is Cost Shifting?

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

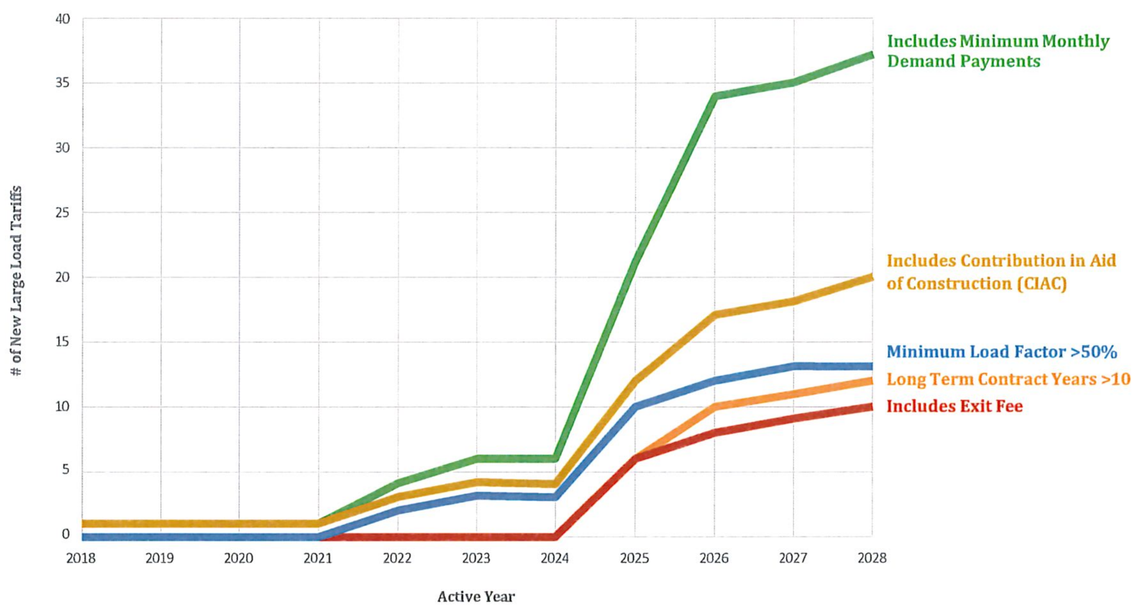
The regulatory framework includes multiple safeguards to prevent cost shifting and ensure customer protections and equitable outcomes.

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 National Lab Expert, April 2026

What the Data Shows: Data Center Rate Impacts to Date

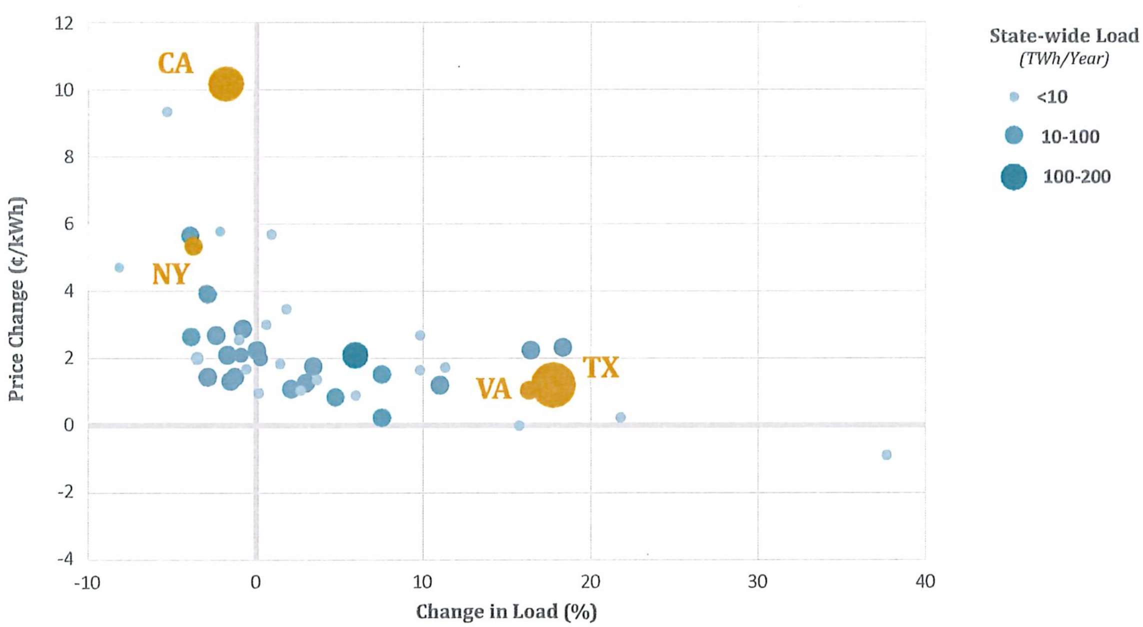
The quantitative literature examining data centers' impact on retail electricity rates is limited, in part due to the recency of the buildout and accordingly limited data.[20] Stakeholder interviews underscored this gap is widely recognized, and that most existing analyses focus on adjacent topics rather 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 National Labs Expert, April 2026

[22] Interview with National Labs Expert, 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.