ENERGY & NATURAL RESOURCES

The Future of Utility Rate Design

Executive Summary

Traditional ratemaking was built for flat load, not today's rapid growth.

- For decades, rate structures assumed modest, stable electric demand and were designed to enable energy conservation. This led to widespread decoupling and efficiency programs that deliberately weakened the link between utility earnings and volumetric sales.
- That rate structure construct now collides with simultaneous shocks: data center and electrification driven load growth, more frequent extreme weather, aging grid infrastructure, and constrained transmission, all of which require rapid, geographically targeted investment.
- Broadly spreading these costs, especially those related to data centers, across residential, commercial, and industrial classes is increasingly contested, as smaller customers push back on what they view as subsidizing upgrades driven by a relatively small number of hyperscale and industrial loads.
- In restructured ISO (Independent System Operator) and RTO (Regional Transmission Organization) markets, "wires only" utilities are further squeezed: they have limited control over wholesale prices yet absorb customer and political backlash as energy and capacity prices climb, particularly in high priced zones.

Existing mechanisms can misalign capital formation, risk, and customer impacts.

- The current cost-of-service revenue requirement framework and rate case cadence have left utilities and regulators reactive relative to the timelines for generation and transmission buildout.
- Both decoupling and discounted, lower margin Commercial and Industrial (C&I) tariffs preserve earnings under flat demand but can reduce incremental system contributions for utilities as large new loads appear, leaving residential and small commercial classes at risk of making up the shortfall to fund capacity expansions.
- Because generation and transmission investments are planned and recovered through separate processes, systems often experience congestion, curtailment, and inadequate reserve capacity, with limited mechanisms to compensate for higher asset utilization.

Future rate design could segment cost responsibility, monetize flexibility, and reward outcomes.

- A more effective rate framework could explicitly and adaptively connect who drives costs with who pays, while tying a greater share of earnings to performance.
- Providing financial incentive for utilities to increase existing asset utilization, such as, by reforming decoupling rate mechanisms, can better align the use of advanced grid solutions to unlock additional capacity in existing infrastructure.
- Deeper regulatory segmentation by customer type, expanded use of largeload tariffs and Bring Your Own Capacity (BYO) mechanisms, and, in some cases, parallel, deregulated affiliates for very large, pricetolerant customers may better align data centers and industrials with the grid investments they require, rather than socializing those costs across the full rate base.
- Scaling dynamic pricing, demand response, and load curtailment can turn customer flexibility into a grid resource, reducing peakdriven upgrades and enabling faster interconnection of new load.
- Performance based regulation, earnings adjustment mechanisms, and selective "recoupling" of revenues to sales can link utility profitability to metrics for reliability, resilience, affordability, equity, and decarbonization.
- Jurisdictions that move first to clarify cost causation, protect legacy customers, and reward utilities for enabling least cost growth will be better positioned to secure capital, attract new load, and manage political risk in the decade ahead.

Introduction

A System Under Strain

The electric utility sector faces a critical challenge: funding the capital investments needed to meet rapid electric demand growth and emerging grid dynamics while keeping power affordable. This pressure stems from converging factors: aging infrastructure, more frequent and intense weather events, higher renewable penetration on both sides of the meter, accelerating electrification, AI-driven data center development, manufacturing reshoring, and transmission constraints that have increased grid congestion. As a result, residential electricity rates in the US increased at a compound annual growth rate of 5.2% from 2020 to 2024, compared with 1.7% in the prior 20 years[1] (Figure 1).[2]

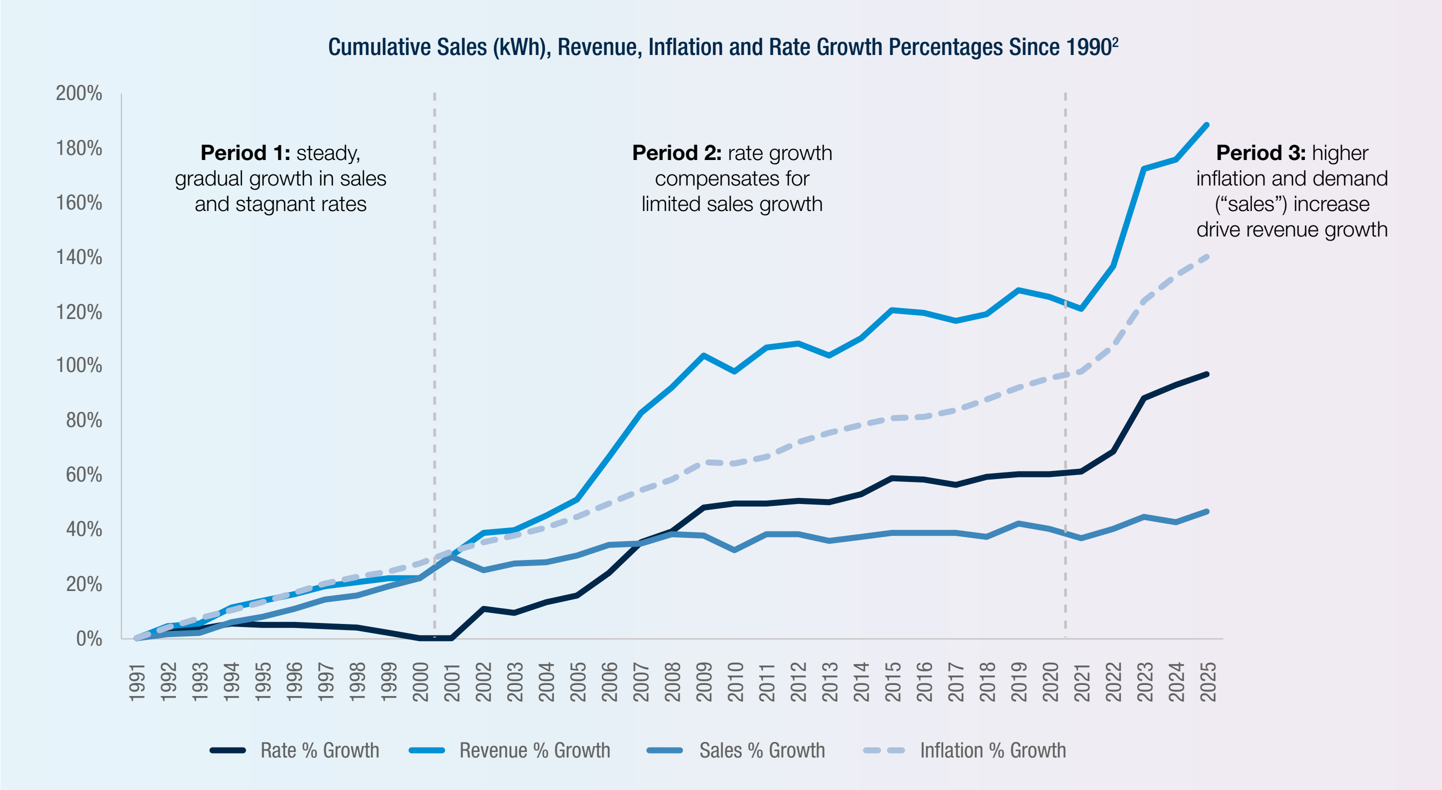
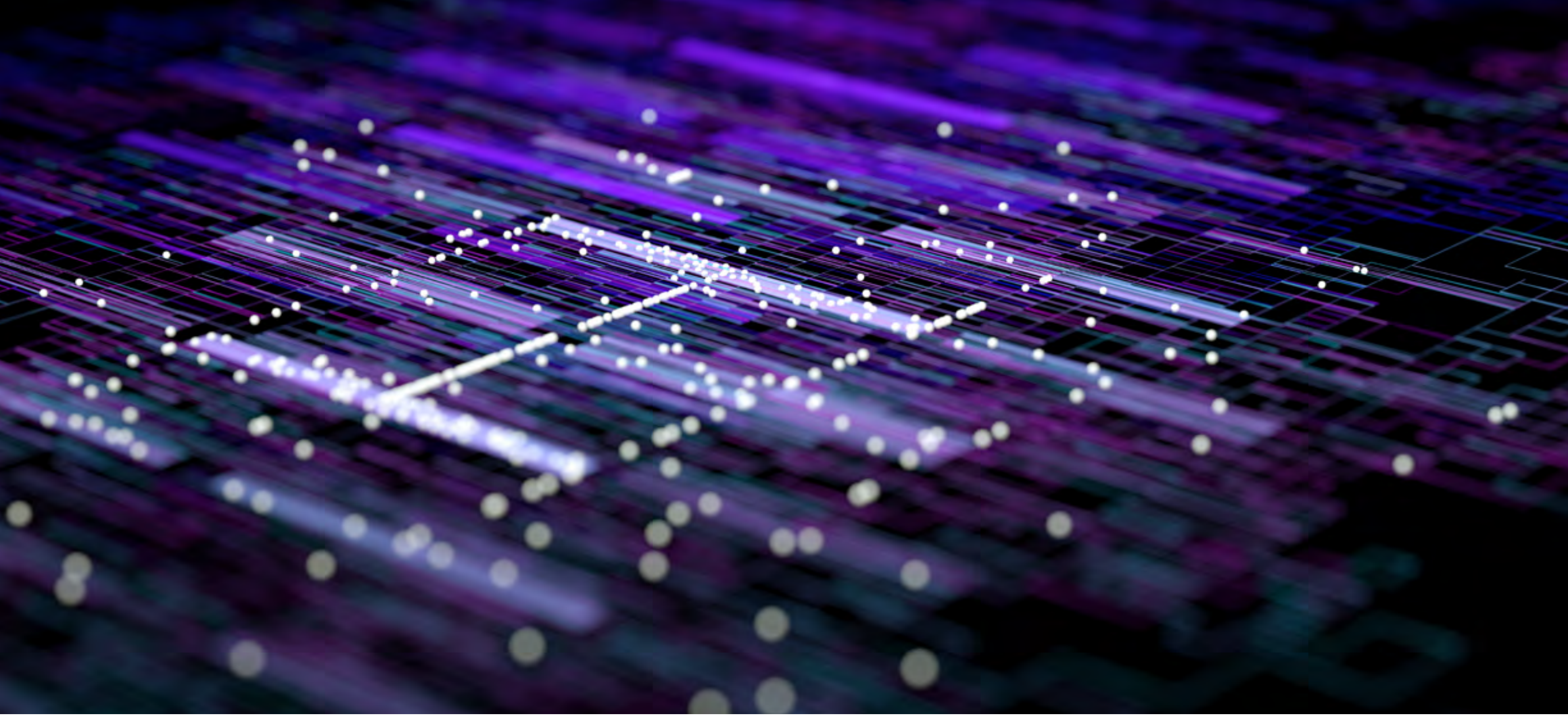


Figure 1. US power consumption and utility revenues percent growth since 1990[3].



Growth in electric demand is evident across the country. The Electric Reliability Council of Texas (ERCOT) received approximately 198 GW of large-load interconnection requests in Q1 2026 alone, with about 86 GW (roughly equal to ERCOT's entire current peak load) under active review, i.e., the projects are under consideration for interconnection[4]. The Pennsylvania-New Jersey-Maryland Interconnection (PJM)'s 2026 Long-Term Load Forecast projects summer peak demand rising by about 58% by 2046, from roughly 160 GW to 253 GW, driven primarily by data centers[5].

To meet demand, utilities and developers are building new generation and transmission. While new transmission has remained slow to materialize, generation capacity has increased by approximately 19%[6] over the past decade, with renewables accounting for an average of 66% of new capacity added annually[7,8,9]. However, the buildout has strained the grid interconnection process: projects now wait an average of 4 to 5 years (up to 7 years in some regions) to connect[10], about a 60% increase since 2017[11]. Even for generation that successfully interconnects, transmission congestion can force curtailment to protect grid integrity. Building new transmission takes longer than generation and faces more NIMBYism (Not In My Backyard).

Meanwhile, the regulatory frameworks governing utilities were built for a different era – one of gradual, predictable demand growth. Utility planning processes are designed to identify investment needed to meet system demand, a task that has grown harder given the rapid, and sometimes uncertain, increases in demand growth. In a few recent instances, when utilities projected sharp departures from business-as-usual load growth (e.g., due to new data centers), estimates have been inaccurate, straining the planning and regulatory process.

Affordability concerns compound these issues. Grid costs are traditionally allocated across "classes" of ratepayers based on an allocation of the cost to serve them, but residential and small commercial consumers increasingly argue that their electricity bills subsidize upgrades perceived to be disproportionately driven by new industrial loads, especially data centers. Even where cost increases are evident, assigning responsibility to specific load types such as data centers is complicated by variation in grid topology, market structure, and regulatory framework across jurisdictions[12]. At the same time, the investments required to address aging grid infrastructure and resilience are putting additional upward pressure on utility rates, with fewer pathways to offset those increases[13].

This paper reviews how we got to the current landscape of utility rates and ways they may be evolving to adapt to the new dynamics of electric demand.

Evolution of Utility Rate Design – How We Got Here

For much of the twentieth century, electric utility rates were designed on the assumption that demand would continue to grow. However, by the 1990s, load growth began to slow, partially due to energy efficiency improvements and a broader shift toward energy conservation[14]. In this environment of limited load growth, regulators needed to solve two challenges simultaneously: ensure a reasonable rate of return on capital investments and preserve gains in energy efficiency.

The most common solution to this challenge was rate decoupling, whereby utilities are guaranteed revenue with their state's PUC, independent of total power sold. Although states use different mechanisms to meet revenue requirements, the general approach is similar and effectively removes the link between utility earnings and the amount of power consumed across the rate base.

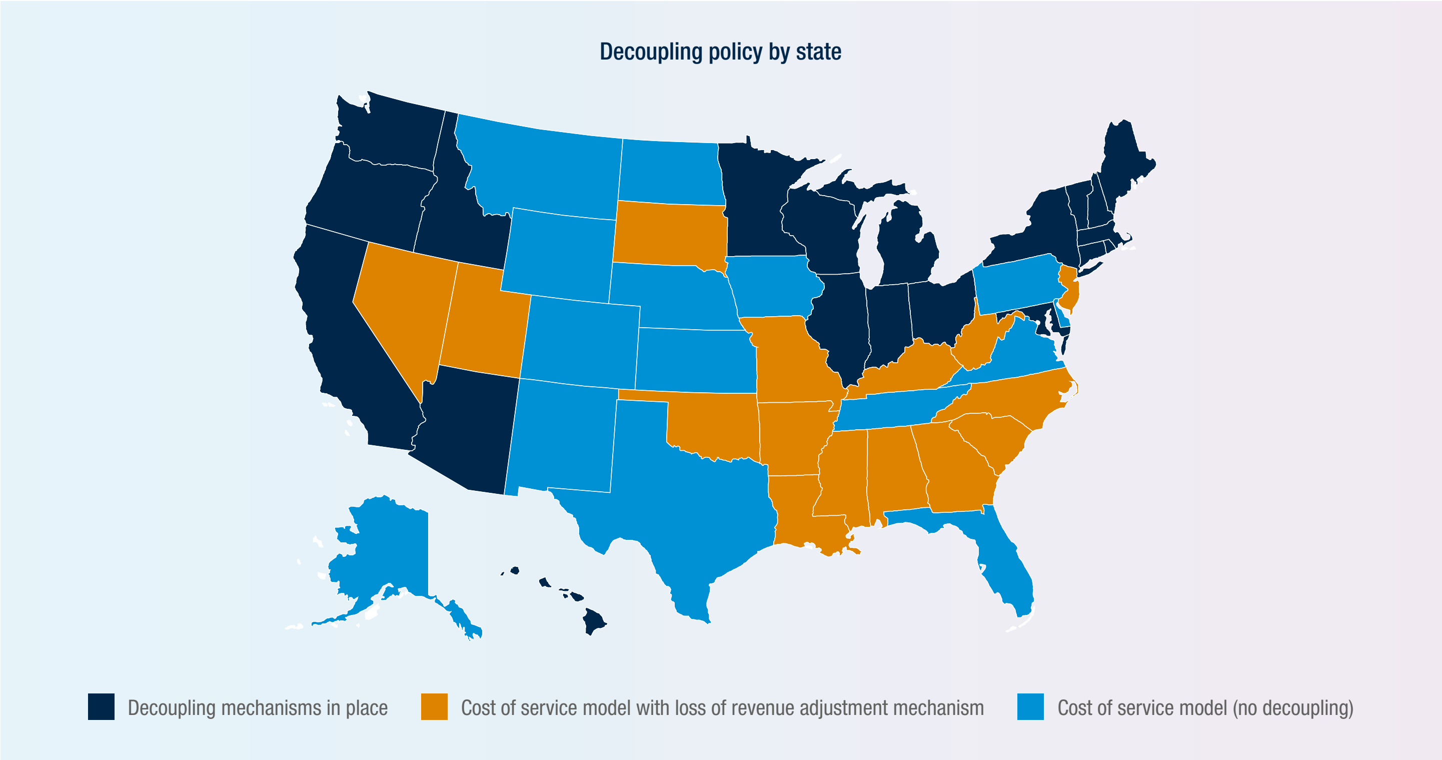


Figure 2. Decoupling policy by state[15,16].

The restructuring of power markets in the late 1990s introduced another disruption to the traditional model. Many vertically integrated utilities divested generation, becoming 'wires-only' utilities that operate transmission and/or distribution infrastructure but procure wholesale power from competitive markets. In this model, transmission and distribution utilities have little influence over the energy price component embedded in customer bills, a dynamic that has grown more difficult as energy prices in many deregulated markets have risen substantially in recent years[17].

As a result, utilities can struggle to enable load growth at the pace required by growing electricity demand, except where incentives already align with existing regulatory conventions. Each structural choice, such as decoupling, generation divestiture, or customer rate segmentation (whereby different customers classes are charged different amounts based on the cost to serve that class) was rational at the time. Taken together, however, they created a system whose incentive structure was calibrated for low, stable growth. That system is now being asked to do something it was not designed to do.

Rate Design Approach Today, And Where It Fails

Revenue Requirements and Rate Cases

The foundation of US utility rate setting is a negotiation process called a 'rate case', whereby investor-owned utilities engage in a public, formalized process with their state PUC[18,19]. Rate cases occur every two to five years, depending on the jurisdiction, and are often timed at the utility's discretion. More frequent rate cases provide a more up-to-date reflection of a utility's current operating environment and customer demand, while lower-frequency rate cases reduce the regulatory burden for both the utility and the PUC.

In every case, the PUC assesses the prudence of investments to determine their recoverability through customer bills.

These costs are included in the utility's revenue requirement, which is defined as:

$$\text{Revenue Requirement} = (\text{Rate Base} \times \text{Allowed Rate of Return on Equity}) + \text{Expenses} + \text{Depreciation} + \text{Taxes}$$

Where the Rate Base is the total value of non-depreciated capital assets, Allowed Rate of Return on Equity is the utility's authorized rate of return on equity (ROE) across capital expenditures made (approved by the state rate-regulating bodies and ranging between 8-12%), Expenses are O&M (operations and maintenance) costs incurred as part of business-as-usual activities such as vegetation management, customer call center operations, or IT services, Depreciation is the total in-year depreciation of capital assets, and Taxes are applicable federal, state, and local taxes paid for the year.

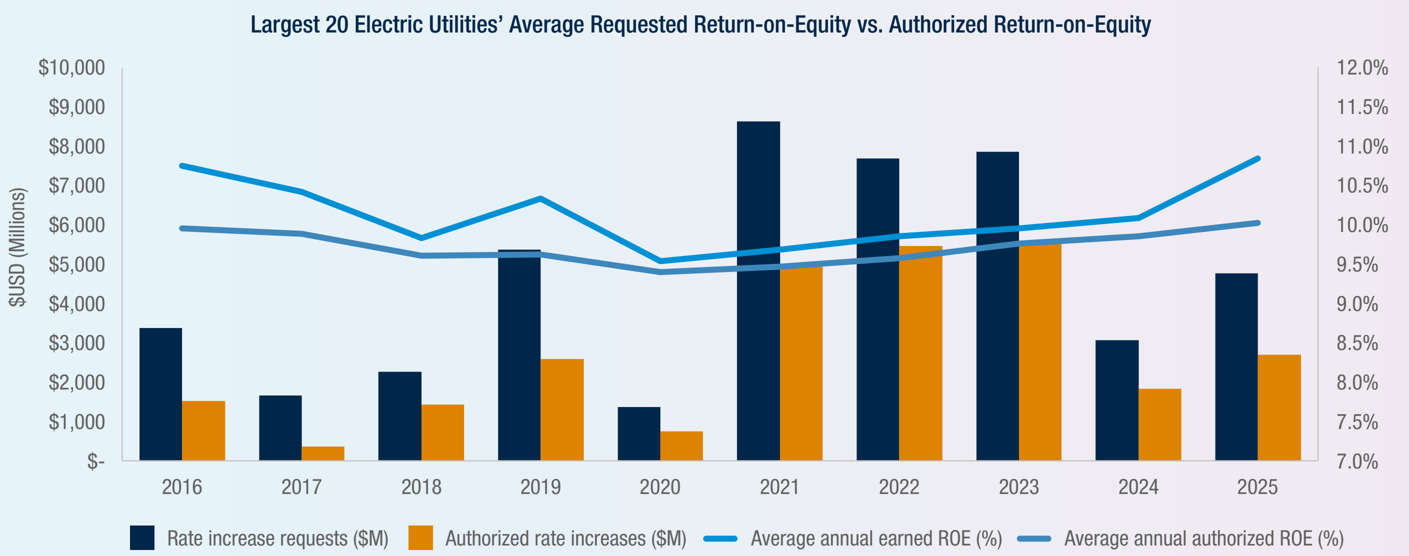


Figure 3. Largest 20 Electric Utilities' Average Requested Return-on-Equity vs. Authorized Return-on-Equity[20]

Utilities typically commence a rate case by petitioning their state utility regulatory body to open a docket. Acceptance of the petition triggers the filing of documentation, ranging from hundreds to thousands of pages of direct testimony and exhibits, detailing the costs the utility deems necessary to operate its system reliably and safely, the requested rate of return on equity for capital investments, and justifications for the underlying investments.

In most cases, other stakeholders, such as government bodies, consumer advocacy groups, environmental organizations, industry lobbyists, local businesses, and individuals will also cross-examine and submit written commentary and/or speak at public hearings, offering perspectives in support of or opposition to elements of the rate case, which the state PUC evaluates.

The process typically yields a decision every few years on the utility's requested rate increase, although outcomes can differ substantially from the request, including cases where the increase is denied altogether. This cadence was designed for a slowly changing operating environment but now contributes to lag in today's fast-changing energy environment.

Ratemaking Formula and Its Limits

Once a rate case is approved and the revenue requirement is determined, a utility's target rate is set as:

$$\text{Target Rate} = (\text{Revenue Requirement})/(\text{Projected Sales})$$

where Projected Sales are typically based on actual power sold (in kWh) during a "test year".

Once a target rate is determined, the actual rate a customer pays depends on whether the PUC employs only cost-of-service or uses decoupling as a rate adjustment mechanism:

- Under a 'cost-of-service' approach, rates are set at the target and held until a subsequent rate case[21]. Utilities operate under a 'throughput incentive' to sell more power, because additional revenue from increased sales volumes is retained by the utility. The utility bears both the risk and the reward from changes in the volume forecast.
- Under a decoupled rate adjustment mechanism, the revenue requirement is fixed, based on cost-of-service ratemaking approach, but rates fluctuate year-to-year to ensure that utilities collect authorized revenue regardless of energy delivered. Utilities are therefore guaranteed a fixed amount of revenue, and no throughput incentive exists to deliver more electrons using existing infrastructure.

The US Department of Energy (DOE) reports that commercially available advanced grid solutions (examples include dynamic line rating, advanced power flow control, topology optimization, advanced conductors) could enable the existing transmission and distribution system to support 20–100 GW of incremental peak demand, roughly comparable to NERC's (North American Reliability Corporation) projected 91 GW of winter peak-demand growth from 2024 to 2033[22].

The rate benefit comes from higher utilization of infrastructure ratepayers have already funded. By moving more power over existing wires, rather than relying only on new, capital-intensive buildout, utilities can spread fixed grid costs over more throughput and reduce upward pressure on rates. DOE estimates that full deployment of these solutions could defer $5–$35 billion in T&D infrastructure costs over five years and that grid-enhancing technologies like dynamic line rating, advanced power flow control, and topology optimization could reduce congestion costs by 25%–50%, implying roughly $5–$10 billion per year in ratepayer congestion-cost relief.

Both rate-setting models involve trade-offs. A decoupled approach incentivizes utilities to use less of their existing capacity, as doing so creates additional operational risks and increases O&M costs. Utilities operating in such a paradigm will therefore tend to invest in build-out of new infrastructure to increase capacity, rather than better utilizing existing infrastructure, which comes at a higher overall cost borne by ratepayers. Advanced grid utilization increases operational complexity and O&M cost, because the grid runs closer to real-time limits rather than on wider reserve margins. Recoupling would give utilities a clearer financial incentive to pursue this untapped capacity: incremental electricity sales could offset added O&M and justify the operational effort.

Advanced grid solutions and demand flexibility are complementary: demand flexibility reshapes load, while grid-side technologies expand how much existing infrastructure can safely carry.

Cost-of-service addresses this issue by incentivizing utilities to generate and transmit more power using existing infrastructure. However, it also creates a throughput incentive, discouraging utilities from promoting and supporting energy efficiency or demand reduction. Regulators and legislative bodies should take these considerations into account when determining how rates are set, because either approach can have unintended consequences if not carefully managed.

Customer Rate Classes

State regulatory bodies and utilities are bound by the Public Utility Regulatory Policies Act of 1978 (PURPA) to set rates "for each class of electric consumers…based on the costs of providing such service to such classes." How that principle translates into a rate structure for each class is interpreted by the state PUC. The PUC aims to minimize cross-subsidization of one customer class by another, but as with other aspects of rate case proceedings, different stakeholders will have divergent perspectives on what defines fair and equitable rate design.

In general, smaller customers pay higher overall prices for energy, due to higher cost to serve via the distribution network. Thus, residential bills tend to have the highest all-in costs on a $/kWh basis, all else being equal. This cost trend is consistent across utilities in other countries as well.

One illustrative example of how utility may structure rates is:

Industrial	Higher capacity fee and the lowest cost per kWh consumed, often with stipulations for a minimum total consumption requirement
Commercial	Higher fixed fee or a low capacity fee ($/kW-month), plus a moderate cost per kWh consumed
Residential	Small fixed fee, plus a high cost per kWh consumed

Stable revenue requirements and decoupled rates mean the recent spike in electric demand could lower bills for legacy customers who now purchase a smaller fraction of total power than in past years. However, the combination of decoupling and lower margin C&I rates can push utilities to prioritize upgrading or building new transmission lines, rather than using advanced grid solutions and load-flexibility to increase utilization of existing lines. The additional capital required to finance upgrades and new builds ultimately raises rates, including residential rates.

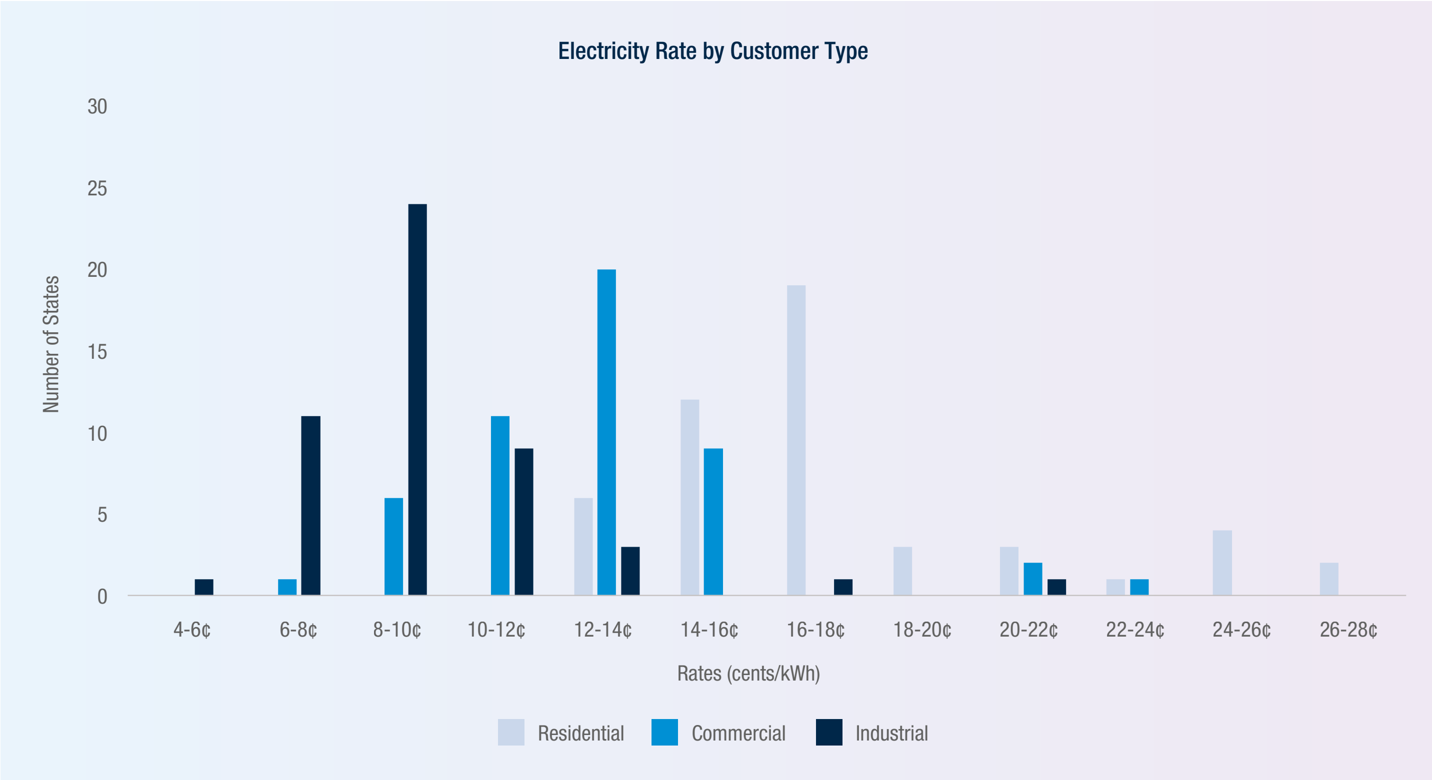


Figure 4. Average US Electricity Rate by Customer Type (2024)[25]

Without specific constructs, such as a large load tariff, the costs associated with transmission upgrades, substation expansion, or new generation capacity enter the utility's rate base and are recovered from all ratepayers, including residential and commercial customers. Where large-load tariffs do address this issue, they have often not been calibrated to capture the full infrastructure costs triggered (see The Impact of a New Load on Residential Electric Rates later in this paper, and commentary from others[23],[24],[25]).

The impact of rates on residential customers is incredibly salient. Total outstanding utility bill debt for US households reached about $25 billion in June 2025, up from roughly $15 billion in early 2022[26]. Electric utility shut-offs exceeded 13 million in 2024, and shut-offs net of reconnections were approximately 2 million[27]. Today, approximately 21 million households (one in six) are behind on utility bills[28]. Meanwhile, utilities requested more than $29 billion in rate increases in H1 2025 alone, double the H1 2024 level[29]. These figures make the cost-causation debate a question of basic affordability and help explain the political intensity behind both moratorium legislation and the White House Pledge.[30] In today's environment of affordability pressure, PUCs also seek to formally or informally limit increases in utility bills to match that of inflation, with varying degrees of success, depending on other factors in the rate case.

Limitations in Conventional Ratemaking

Conventional ratemaking does little to reward reserve capacity and localized congestion relief achieved through accelerated transmission expansion and new builds beyond what reliability standards strictly require. Utilities have historically earned on assets that are clearly in rate base and demonstrably "used and useful," not on maintaining flexible, dispatchable capacity that runs infrequently but is crucial during peak or stress events. This bias toward minimum compliance rather than robust resilience encourages underinvestment in demand flexibility and energy storage that could smooth volatility and reduce risk. Similarly, the framework tends to support only incremental transmission expansion: new lines are justified to interconnect specific plants or relieve acute congestion, while broader, anticipatory transmission that would unlock lowcost renewables or regional balancing often struggles to clear costbenefit and prudence tests.

Even detailed national level analyses underpredict infrastructure needs. The four-year capital expenditure plan of Exelon, a major utility and owner of transmission and electric distribution across the Midwest and Mid-Atlantic, outlined a four-year capital spending plan (2026 to 2029) of $41.3 billion, about 70% of which is transmission (~$28 billion)[31]. Exelon also identified $12–$17 billion of potential transmission spending not included in their capital plan, bringing total identified transmission investment to $40–$45 billion. For Exelon alone, these amounts exceed some transmission capex projections published as recently as 2020 for the entire US[32].

In organized wholesale markets such as MISO and PJM, pricing challenges compound these structural issues. Volatile energy and capacity prices, evolving rules, and sometimes muted scarcity signals can leave utilityserved customers effectively acting as price takers as power costs climb. Utilities pass through a large share of market costs under fuel and purchasedpower adjustment mechanisms, so customers shoulder rising prices without having much visibility or leverage over the underlying procurement and investment decisions. At the same time, utilities have weaker incentives to pursue sophisticated hedging, longterm contracting, or demandside resources when the regulatory framework largely allows them to flow market risk through rather than actively manage it.

In PJM specifically, the dynamic is stark: local distribution utilities must procure power from regional markets and flow those costs directly into retail rates, causing customer bills to spike even when the utility's own delivery charges remain flat. At the same time, market rules and pricing structures have not kept pace with renewables, storage, and other emerging technologies, weakening incentives for flexible, low-cost resources and further inflating wholesale prices. The result is a growing disconnect between those who set the price of energy and those who are held accountable for it, leaving transmission and distribution utilities with limited levers to manage rising pass-through costs. Recently, the PJM auction markets for generation capacity hit the market's price cap for the second consecutive auction[33], prompting governors from all 13 PJM states to gather at the White House to sign a joint "Statement of Principles", pressing PJM to conduct an emergency capacity auction and cap power prices[34]. In New Jersey, where electricity is generated and transmitted with PJM as the market operator, these pressures have led to that state's governor declaring a state of emergency "on utility costs" broadly, underscoring how little control wires utilities have over wholesale prices embedded in customer bills. The declaration and subsequent executive orders direct the use of public funds to offset electricity bill increases anticipated in June 2026 and direct the state PUC to "ensure alignment with delivering cost reductions to ratepayers"[35].

Performance-Based Regulation: An Increasingly Popular Update to Ratemaking Policy

An emerging and evolving paradigm in utility regulation aligns financial incentives with performance outcomes through performance-based regulation (PBR). Rather than simple recovery of Return on Equity (ROE) through capital investment, regulators tie a portion of recoverable utility revenue to outcomes aligned with public policy goals, which can span different criteria. Performance based regulation hinges on clearly defined outcomes and metrics that determine whether a utility earns rewards or faces penalties.

Assessing performance under performance-based regulation frameworks typically requires an Earnings Adjustment Mechanism (EAM), which allows a PUC to translate results into financial upside and consequences, sometimes adding incentives when utilities exceed targets, and imposing penalties or downward rate adjustments when they fall short. Common criteria include outage duration and frequency, customer satisfaction, and customer affordability. Increasingly, equity-oriented metrics like improved reliability in disadvantaged communities and targeted energy-burden reductions are also being built into performance scorecards.

EAMs can be implemented in different ways. In New York, EAMs sit atop traditional cost-of-service rates and incentivize utilities explicitly for achieving policy-aligned outcomes. Con Edison can earn basis-point adders on its allowed ROE when it exceeds quantitative targets for system peak reduction, customer energy efficiency (i.e., kWh saved), and expedited DER interconnection timelines[36]. Each metric has a target band with a sliding scale of rewards or penalties on either side, capped in dollars per year[37].

Hawaii employs a distinctive earning sharing mechanism (ESM) and performance-based regulation incentive that are core to earnings. Hawaiian Electric operates under a multi-year revenue cap and compares achieved ROE to a 9.5 percent target; if actual ROE lands more than 300 basis points above or below the cap, a share of the over- or under-earnings is automatically flowed back to or recovered from customers through rate adjustments.

In addition, Hawaii's performance incentive mechanisms put specific dollars at stake for metrics such as interconnection speed, low- and moderate-income efficiency, and advanced metering, allowing Hawaiian Electric to "earn more by performing better" and see its bottom line move up or down in near real time based on those scorecards.

Although performance-based regulation has been used as a policy tool in the US over the last 15 years[38], it has been implemented at least to some degree in a majority of states[39,40,41]. Most recently, Ohio PUC staff proposed a mechanism to adjust AES Ohio's ROE by ±25 bps based on annual capital expenditure performance[42]. As performance-based regulations continue to evolve, they are beginning to encompass targets beyond customer service, incorporating emissions and cost targets in many instances[43]. As adoption grows, the toolkit available to policymakers for shaping utility behavior is likely to expand alongside it.

Large Load Tariffs and Related Instruments: Assigning New Costs to New Demand

A large load tariff applies cost causation to a utility's largest new customers. It is a regulator-approved schedule of rates, terms, and conditions that requires these customers to pay for the incremental generation, transmission, and distribution necessitated by their arrival, rather than spreading those cost across the rate base. These customers are mostly data centers (including AI compute and crypto-mining) but can also be load-intensive manufacturing/industrial facilities, e.g., semiconductor fabs, EV/battery plants, or steel facilities. A single site can request anywhere from 100 MW to more than 1,000 MW (equivalent to the demand of a large city), and serving the load often requires new generation and transmission capacity.

A standard C&I rate assumes a customer whose load ramps gradually and predictably, remains in operation for many years, and is small relative to the system. A load tariff is designed for customers that meet none of these assumptions and therefore require a different set of terms:

- Minimum bill or "take-or-pay" charge (the customer pays for a set-share of contracted capacity whether or not it draws the power).
- Long minimum contract terms (often 10-20 years).
- Collateral, deposits, and creditworthiness requirements.
- Exit and termination fees to cover stranded costs.
- A defined ramp schedule for loads and upfront funding of interconnection studies and dedicated facilities.

These terms protect existing ratepayers from stranded costs if a project shrinks or never materializes, and they screen out speculative interconnection requests that inflate load forecasts.

According to the SEPA/NCCETC DELTa tracker[44], regulators approved 29 large load tariffs in 2025 alone, up from 14 such approvals in the prior seven years (2018 to 2024). By March 31, 2026, 77 total tariffs have been considered (51 approved and 26 pending), and tariffs/service rules had been proposed at 60 utilities across 36 states. The primary driver is data center demand: EPRI projects data centers could consume 9% to 17% of US electricity generation by 2030, up from roughly 4% to 5% today[45]. Rising retail bills and public resistance to subsidizing data centers have added political pressure, reflected in the White House's 2026 Ratepayer Protection Pledge[46]. Improving affordability is not inherently a partisan issue: political will exists across the ideological spectrum to lower the price of electricity, though there is disagreement on the best means to do so[47,48].

Prior to 2025, a typical large load tariff size-threshold was at-or-below 25 MW, but it now commonly falls between 50 and 150 MW49. The average "minimum bill" for large load tariffs is ~80% of contracted capacity and ranges from ~70% to 100%[49]. Contract terms range from as little as four years in some proposals to 30 years, with approved minimums typically 10 to 20 years. The underlying factors that drive a large load tariff's proposal also vary depending on circumstances, with most beginning as a utility-filing or settlement that intervenors contest before a commission rules. However, others are driven by legislative action. Oregon's POWER Act and Minnesota's HF16 directed their commissions to create a separate class for very large loads; and Utah, Missouri, and Kansas have passed comparable laws. Alternatively, some utilities negotiated directly with large customers rather than implementing large load tariffs. Most recently, FERC issued show cause orders requiring all six ISOs (PJM, MISO, SPP, CAISO, ISO-NE, and NYISO) to "justify or reform the rules that govern how data centers, manufacturing facilities, and other large energy users connect to the electric grid,"[50] with the goal of improving interconnection speeds for large loads.

Table 1. Example of Recently Proposed or Approved Large Load Tariffs[51,52,53,54,55]

Utility (State)	Background	Size Threshold	Contract Term	Minimum Bill/Take	Cost Recovery	Status
Indiana Michigan Power (IN)	Settlement amendment to industrial tariff	70+ MW per site; 150+ MW aggregate	12-year minimum after ramp	80% of contracted capacity	T&D vs. generation split deferred to a later proceeding	Approved, IURC Cause 46097, Feb. 2025
AES Indiana (IN)	Customer-specific contract under state law (HEA 1007)	Project-specific (Google, about 390 MW)	15-year minimum	Minimum-usage commitment with financial assurances	Google pays 100% of incremental generation and infrastructure; 100% of new transmission to serve it	Pending, filed Apr. 2026; order expected Sep. 2026
PGE (OR)	Class mandated by the POWER Act; terms set by PGE, modified by the commission	20 MW (data centers)	10 years at 20 MW, up to 30 years at 220 MW or more	90% gen and 90% transmission demand	100% of distr.; single-customer transmission assigned; shared T&G via "Peak Growth Modifier"	Approved, OPUC Order 26-154, May 2026; effective June 10, 2026
Pennsylvania (model tariff)	Commission-developed statewide model for all electric distribution companies	50 MW individual; 100 MW aggregate	5-year minimum after three-five year ramp	80% of contracted demand	"But-for" CIAC[56]: customer covers distribution and transmission interconnection costs	Final order entered May 12 2026 (model framework)

In lieu of a large load tariff, at least 12 states have considered statewide moratoria on data centers. More than 300 data center-related bills were introduced in 30 states in the first six weeks of 2026[57]. However, these efforts have not been widely successful and risk indiscriminately banning economic development that constituents may support. On April 15, Maine's legislature passed what would have been the first-in-nation construction ban on data centers with more than 20 MW through November 2027, but the governor vetoed it because it lacked an exemption for a project already in development[58]. Vermont S.205 proposes a freeze through 2030 but has not been enacted.

Virginia's HB1515, a moratorium to halt all data center applications through Jul 2028, has stalled. Minnesota's two bills died May 18 when the Legislature adjourned without a hearing[59]. One of the only successes in halting data center development is in New York, where the legislature passed the Responsible Data Center Development Act, imposing a one-year permit moratorium for facilities ≥20 MW. Most enacted bills (e.g., Florida SB 484, Oklahoma HB 2992, Texas SB 6, Oregon POWER Act) use tariff and cost-allocation tools rather than construction bans, reinforcing the need for regulators to determine appropriate tariff and rate design.

The Impact of a New Load on Residential Electric Rates

To illustrate the impact on residential rates from the interconnection of a new 500 MW data center, we modeled five market scenarios. Full parameters are provided in the Appendix. Our model considers the impact on rates across five different scenarios, detailed in Table 2 below.

Table 2. Market scenarios under which a new data center is interconnected.

Scenario	Description
Integrated utility + standard industrial tariff	A vertically integrated utility with no special rate class for data centers. When a new data center customer connects, it pays the same rate as other large C&I customers. The utility builds the infrastructure required, adds it to the rate base, and recovers the cost from all customers through the standard rate case process, either directly through a COS model, or indirectly through decoupled rates. No mechanism exists to ring-fence data center infrastructure costs from the general customer pool.
Integrated utility + large load tariff (partial recovery)	A vertically integrated utility with a dedicated large-load tariff in place, requiring the data center to directly cover 85% of the transmission and distribution costs and 60% of the generation costs, through a minimum 14-year contract. This approach reflects the structure of Virginia's GS-5 (approved November 2025) and AEP Ohio's Data Center Tariff (approved July 2025), mirroring the current policy frontier.
Integrated utility + large load tariff (full recovery)	Infrastructure costs triggered by a data center connection are fully recovered from the data center owner, with no costs socialized to the rate base, fully insulating residential bills from data center infrastructure costs. The utility still earns its regulated ROE on the new rate base and is not disadvantaged, but the recovery vehicle is the data center's tariff, not the general revenue requirement.
Restructured market	A wires-only utility operating within a restructured ISO/RTO where generation is procured through the market, either via a power + capacity market (e.g., PJM) or a competitive retail market (e.g., ERCOT). The utility owns and operates transmission and distribution infrastructure and recovers costs to operate and maintain the wires, while passing through wholesale capacity and/or energy costs to retail customers, which are capacity borne by the entire market.
Behind-the-meter power with a grid connection	A data center co-locates at a generation facility and takes power behind the meter but still interconnects to the grid. The generation asset is ring-fenced from the general rate base through a commercial agreement. The residential impact differs from a direct rate base cross-subsidy, as residential customers are affected through 1) the utility being unable to recover interconnection costs from the data center, and 2) a potential reduction in generating capacity. In this case, residential customers would bear the cost of T&D infrastructure, but not generation, just like in the restructured market scenario.

The impact on rates from each scenario is shown in Figure 5 below.

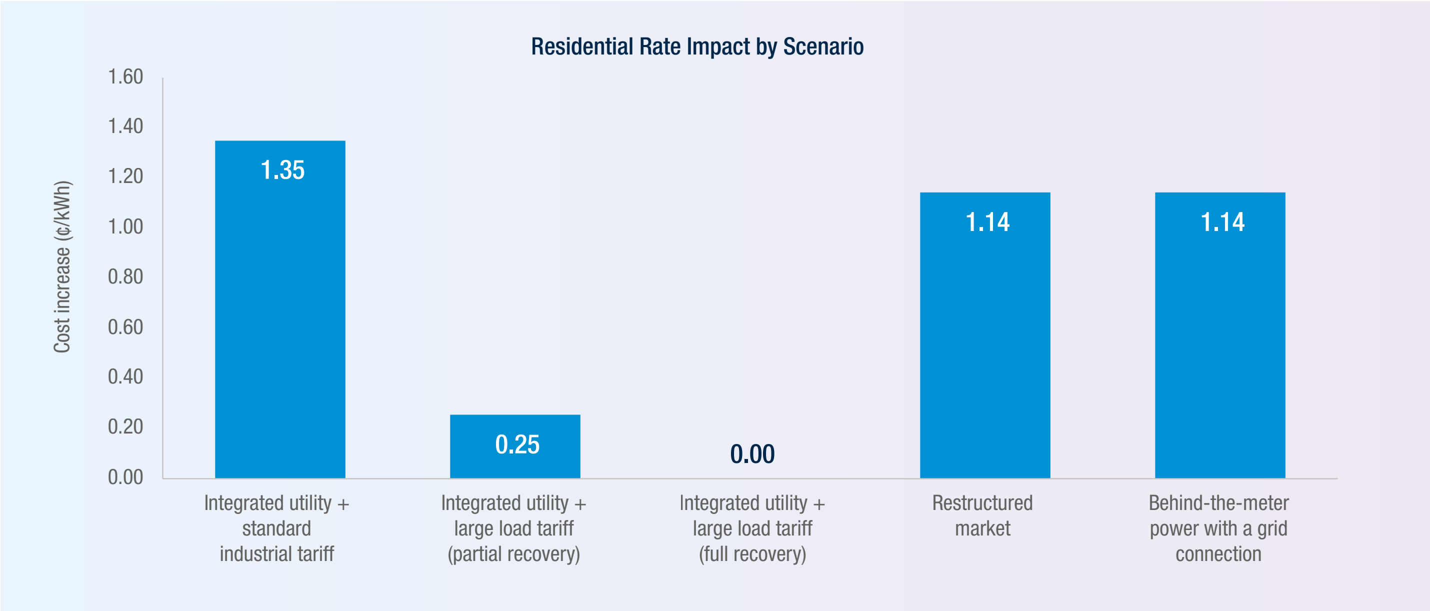


Figure 5: Impact of 500 MW data center on residential customers, based on market structure

The results of this analysis indicate that residential rates can vary up to 1.35¢/kWh – a ~9% increase over the modeled base rate. Across all scenarios, physical infrastructure, demand, and utility size, are held constant, underscoring how critical rate design is to the question of affordability. These findings align with prior work on the topic, including analyses of actual energy costs, which report that data centers can increase residential costs by as much as 2.7x within five-years[60,61,62].

Other Evolutions in Rate Design

The approaches described here, while the most widespread, are not the only ones. Several additional approaches are being trialed in various jurisdictions and could see increased adoption in the future.

One approach embeds performance-based regulations directly into large-load tariff structures rather than placing it alongside them. Oregon's Schedule 96 ties interconnection approvals to emissions compliance and functions as a tariff that simultaneously serves as a performance-based regulation mechanism. FERC's December 2025 PJM co-location order[63] includes a directive for PJM to report on "enhanced load forecasting and demand flexibility measures," making a performance-reporting obligation one step below a formal EAM. The trajectory is moving from EAMs layered atop rate cases to performance conditions embedded within major tariff approvals.

In 2022, California AB 205 mandated the state's first income-graduated fixed charge (IGFC) for residential electric customers, now implemented by all three major IOUs (investor owned utilities). The structure establishes a fixed monthly charge of $6, $12, or $24.15 depending on income level, paired with a $0.05–$0.07/kWh rate reduction[64]. This change is not incremental: California is the first major US jurisdiction to structurally shift cost recovery from volumetric usage to income-segmented fixed charges at residential scale. The policy goals are explicit: lower the marginal price of electricity to encourage electrification (EVs, heat pumps), while making fixed-cost recovery more equitable.

Separately, the currently proposed California AB 710 would mandate optional dynamic pricing tariffs for all large IOUs by 2028 and require an advanced metering infrastructure deployment feasibility analysis by 2029[65]. This shift would enable a more dynamic time-of-use (TOU) approach to rate setting, and similar approaches are under considered in other states. At the utility level, Xcel Energy (Colorado) completed its revised residential TOU transition in November 2025[66]. The commercial implications for this transition are substantial: Enverus analysis indicates data centers able to curtail load can save more than $20M annually through real-time pricing strategies[67]. TOU is no longer a conservation tool aimed exclusively at residential load-shifting. It is evolving into a pricing architecture that makes demand flexibility economically rational for large loads and, in some cases, is being mandated as a condition for operation.

Several grid operators and states are piloting "Bring Your Own (BYO) Generation/Capacity" frameworks that allow large loads to accelerate interconnection by committing upfront to procure or fund dedicated new generation. The Southwest Power Pool is implementing its High Impact Large Load initiative, establishing protocols for large loads to enter the queue with an associated generation resource, compressing study timelines[68]. PJM's "Bring Your Own New Generation" proposal creates a similar expedited path[69]. In a February 2026 report, North Carolina's Energy Policy Task Force recommended a bring your own capacity procurement pathway as a formal alternative to standard queue processes[70]. On the retail side, NV Energy and Google's Clean Transition Tariff implements a BYO framework at the distribution level[71]. Across all these approaches, large loads that secure their own supply are faster to energize, cheaper for the system, and less risky for existing ratepayers, making a formal expedited pathway an appropriate reward.

Defining a Path Forward

What Can Be Done Within Existing Frameworks

For regulators, the question is no longer whether to change rate design, but how to do so quickly and equitably while achieving the intended outcomes. Jurisdictions that move first to modernize rates by clarifying cost causation, protecting legacy customers, and explicitly rewarding utilities for enabling new load at the least cost will be better positioned to attract investment and manage political risk. For utilities, the opportunity is to proactively propose new tariff structures, performance metrics, and business models that embrace growth rather than resist it, while making a clear, data-driven case for how these changes keep bills affordable for existing customers. In a world in which timelines for load growth are measured in months rather than years, it is imperative to act quickly to address the existing affordability challenge.

At the same time, regulators must operate within pre-defined boundaries. Rates must be "just and reasonable"; this is the basic legal test every rate must meet. They cannot be unduly discriminatory, meaning customer classes can be charged differently only when the difference reflects the cost of serving them, not arbitrary preference. Costs enter rates only if they survive prudence review (i.e., a utility spent the money reasonably, given what it knew at the time), and anything included in the rate base must pass a "used-and-useful" test (i.e., the asset is actually serving customers; idle or standby capacity generally cannot earn a return). The 1944 Supreme Court case FPC v. Hope Nat. Gas Co. established that rates must leave the utility a return high enough to remain financially sound and attract capital, and therefore cannot be set so low as to be "confiscatory". Specific statutes also define regulator authority: PURPA at the federal level, and a growing body of new state legislation directing how large loads are treated.

Beyond written law, there is also a body of principle and accepted practice that commissions and intervenors argue from. The best-known example is Bonbright's criteria[72], which include rate structures that reflect cost causation (each class pays the costs it drives), economic efficiency (prices that signal efficient use), and revenue adequacy and stability (rates that reliably cover the utility's costs without wild swings). Other commonly followed principles beyond those elucidated by Bonbright include a "cost-of-service" convention (building rates up from the measured cost to serve each class) and "gradualism" (phasing in changes to avoid rate shock, even when cost causation would justify a sharper move).

The policy options available to rate makers are numerous, but they are not infinite. When considering novel approaches for future rate design, regulators and other stakeholders must operate within these restrictions. Some approaches are available today and fall within existing regulatory authority. Others may be within regulatory discretion but contested. Still others would require statutes and are currently beyond the authority of PUCs.

A non-exhaustive list of such policies includes the following:

Approaches available to regulators within existing regulatory frameworks

- **Further regulatory customer segmentation:** Applying different rules and enacting different compensatory mechanisms to distinct customer classes can shield existing customers from the impacts of interconnecting new large loads. This approach builds on traditional utility tariff structures – today, large load tariffs have been enacted in 23 states, primarily targeting new data centers, and the pace implementation is increasing[73]. Some utilities have made time-varying rates the default for customer classes and have begun piloting more granular dynamic pricing.
- **Increased performance-based regulation:** Performance-based regulation currently spans a wide range of utility behaviors, from reliability and customer service to decarbonization and bill reduction, but its next frontier may be shaping utility conduct around large load growth. As interconnection pressures mount, state PUCs are increasingly likely to deploy performance-based regulation as a policy tool, rewarding utilities in business-friendly states for rapidly enabling large load interconnection and penalizing those in more consumer-protective states when interconnection costs are allowed to flow through to existing customers.

Approaches potentially within regulatory discretion but which may be contested

- **Demand response and load curtailment:** Voluntary demand response and mandatory load curtailment invert the traditional approach of power generators responding to demand signals by requiring or requesting consumers to reduce power consumption. These approaches reduce peak-period power demand and limit maximum grid strain, and they can be employed by customers ranging from single-family households to hyperscale data centers. While demand response by data centers has been popularized as a means of accelerating interconnection, it is feasible only for specific types of facilities and is generally viewed as a less palatable solution by data center operators.
- **Rate "recoupling" inverts the logic of decoupling.** Where decoupling removed the link between utility revenue and power sold deliberately, to protect efficiency gains, recoupling would restore that link selectively, giving utilities a direct financial incentive to enable and serve new load growth using existing infrastructure as much as possible. In jurisdictions where the imperative has shifted from conservation to capacity expansion, the policy rationale for decoupling has weakened. Recoupling need not be universal; targeted mechanisms that tie incremental revenue to incremental load served could suffice, and such mechanisms are beginning to appear in several states[74,75,76].

Approaches that would require statute, beyond the authority of PUCs

- **Deregulated utility operations:** Going a step beyond segmenting how different customer types are treated with regard to rate structures, regulatory bodies could allow utilities to operate a parallel de-regulated business that serves customers such as large industrial or data center facilities. These de-regulated arms would assume greater risk, without a guaranteed a rate of return, but could invest in large generation and transmission projects with less regulatory oversight and enjoy higher returns from less price-sensitive customers.
- **Further deregulation of power markets:** Notably, ERCOT (the ISO/RTO for much of Texas) operates an 'energy-only' market in which generators are paid exclusively for the actual energy they produce with no capacity payments. The interconnection process in ERCOT is designed in such a way that rather than using interconnection studies to ensure a new generator can be added to the grid with minimal impacts on the rest of the system, impact studies are limited to only the physical infrastructure needed to interconnect the plant to the grid, and real-time pricing and curtailment are used to manage grid congestion. ERCOT attracted significant volumes of renewables and data centers, but challenges remain with large weather-related outages and high price volatility.

Each options carries its own considerations and tradeoffs. Ultimately, the next phase of rate design will be judged not by how well it preserves legacy frameworks, but by how effectively it supports rapid infrastructure buildout without unfairly shifting costs to existing customers. The most effective approaches will combine ratemaking tools with incentive structures that reward utilities for enabling growth while protecting legacy customers.

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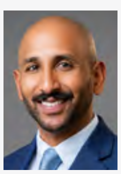

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Appendix

Modeling Limitations include:

1. **Revenue requirement is simplified:** The model excludes depreciation, O&M, and taxes, which may overstate absolute bill impacts. Relative archetype ordering is unaffected; ¢/kWh figures should be treated only as directional.
2. **Normalized baseline is a composite hypothetical utility:** Applying a Mid-Atlantic cost structure to California and Texas archetypes makes mechanism comparisons valid but absolute numbers are indicative only.
3. **Single-event framing understates cumulative impact:** One 500 MW interconnection in isolation does not capture sequential load additions or rate case overlap. In markets with tens of gigawatts in the pipeline, the real residential exposure is materially larger.
4. **Three-year ramp and ten-year recovery are uniform assumptions.** Real construction timelines, rate case cadences, and contract structures vary. Virginia GS-5 uses a fourteen-year term; ERCOT timelines differ structurally from PJM. Uniform assumptions make trajectory charts comparable but reduce jurisdiction-specific accuracy.
5. **Flexible load and demand-side response are not modeled:** The model treats data center load as fixed and passive, and it does not capture the potential for flexible load arrangements, curtailment provisions, or demand response programs to reduce the incremental infrastructure build that drives residential cost exposure.

Model Assumptions:

Parameter	Value	Unit	Sources/Notes
Baseline residential rate	0.148	$/kWh	Weighted average by customer number of Dominion (13.4¢) and Georgia Power (15.5¢) rates. Source: EIA Form 861 2024
Monthly consumption	1,000	kWh/mo	Composite residential customer Source: EIA Form 861 2024
Baseline monthly bill	$148	$/mo	Base rate x monthly consumption
Residential customers	3,000,000	customers	Representative number of customers for a mid-size IOU Source: EIA Form 861 2024
Total annual system sales	85,000	GWh/yr	Hypothetical composite mid-size IOU Source: EIA Form 861 2024 weighted average
Residential T&D cost share	55%	%	Based on Dominion SCC testimony (2025)
Residential gen cost share	40%	%	Based on approximate share of total revenue from residential customers Source: EIA Form 861 2024 weighted average
DC-attributed T&D capex	5,000	$M	Based on assumed T&D capex of $10M/MW; actual costs can vary widely by a factor of 2 or more
DC-attributed gen capex	1,250	$M	Based on the cost of a new combined cycle gas turbine power plant at $2.5M/MW
Allowed ROE	9.9%	%	Hypothetical composite: Dominion 9.8% / Georgia Power 10.3%. Source: Regulatory Research Associates 2024
Cost recovery horizon	10	years	Typical cost recovery time horizon
Cost ramp-in period	3	years	Typical regulatory and construction lag
Data center load	500	MW	Assumption based on the size of a typical hyperscale facility (the largest facilities are 1+ GW)
Data center capacity factor	85%	%	Typical capacity factor for a data center

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