2026 White Paper

Win-Win Watts:

When Can Data Centers, Efficient Electrification, and New Loads Lower Electricity Prices?

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SUMMARY

Can new electricity demand from data centers, electrification, and other sources actually *lower* average retail electricity prices? Despite widespread concerns, the answer is sometimes yes. This paper synthesizes economic theory, recent empirical and modeling evidence, and emerging tariff designs to clarify the conditions under which load growth can support affordability for existing customers while enabling investments in clean, reliable infrastructure.

Price impacts depend on whether serving new customers costs more or less than the average cost of serving today's customers. If incremental costs are low, because the system has spare capacity or new supply is relatively cheap, added load can reduce average prices. If incremental costs are high, because major new infrastructure is required, average prices can rise.

Several factors shape the answer: available spare capacity; load factor and net peak coincidence; proximity to existing infrastructure; and the cost of new generation, transmission, and distribution upgrades. Current empirical and modeling studies suggest that **load growth can meaningfully moderate price increases under these conditions**, though long-run causal evidence remains limited.

Meeting growing load affordably, reliably, and sustainably requires action in three areas: 1. **Proactive planning t**hat links emerging demand sectors (AI, electrification, and new manufacturing activity) with clean energy and grid investments; 2. **Rate design and cost allocation** that protects existing customers from cost shifting; 3. **Demand flexibility** that reduces net peak contributions and defers capital spending. These three levers, detailed in Sections 4-6, largely determine whether beneficial outcomes are achieved in practice. EPRI's DCFlex initiative is testing practical approaches to demand flexibility, with the goal of turning data centers into grid assets.

Under the right conditions, growing load can:

- Lower average electricity prices by spreading sales-independent system costs over more kilowatt-hours;
- Improve the utilization of existing assets and enable more efficient grid planning;
- Accelerate deployment of clean electricity resources and emerging technologies; and
- Support better system operations and lower emissions.

Whether those "win-win" outcomes are realized depends on rate design, infrastructure needs, and policy choices that affect whether new loads cover their costs and risks. Some answers depend on testing new technologies and business models, such as DCFlex's demonstrations of data center load flexibility, that could offer new tools for managing growth while protecting affordability.

1. INTRODUCTION

Data center deployment has increased rapidly with the proliferation of artificial intelligence (AI) applications and other computational service demands. These trends have important implications for power systems, especially with gigawatt-scale service requests, and raise the question: **Under what conditions does adding large loads reduce or increase electricity rates for existing customers?**

Retail electricity prices have been rising with inflation in most states through 2024 (EPRI, 2025a; Wiser, et al., 2025).[1] More recent upticks and utility rate requests have raised concern that surging data center demand and other large new loads could shift costs to other customers given their enormous electricity consumption and billions in planned grid investments. These changes occur alongside continued growth in demand from electrification in transportation and buildings, which can lower overall household energy spending even while electricity expenditures increase (EPRI, 2025a). Data centers have been a recent focus due to their unprecedented growth (EPRI, 2025b), but the proliferation of electric vehicles and greater electrification of space and water heating in buildings and of industrial processes are also expected to drive load growth in the long term.

This paper analyzes the conditions under which load growth could lower average electricity prices by discussing factors that influence these interactions (Section 2), current empirical and modeling evidence (Sections 3 and 4), and rate design considerations in theory and practice (Section 5).

2. THE ECONOMICS OF LOAD GROWTH: WHEN NEW LOADS LOWER (OR RAISE) ELECTRICITY PRICES

From a system perspective, new demand from data centers and other large loads can either lower or raise average electricity prices for existing customers.[2] The key question is whether the long-run incremental cost of serving new load is higher or lower than the system's average cost.

If the extra cost is lower than today's average, new load can lower average prices through two channels: 1. Spreading fixed system costs (i.e., that do not vary with sales volumes, including generation capacity, transmission and distribution, customer service, and policy-related costs) over more kilowatt-hours; 2. Adding generation at costs below the current fleet average. The first channel dominates when spare capacity exists; the second matters when new generation is cheaper than the incumbent fleet. Both are more likely to benefit existing customers when upgrades can be planned and built efficiently, and when the new load has a relatively predictable utilization that can be served with low-cost resources.

If the extra cost is higher than today's average, new load can put upward pressure on prices. This can occur when serving the new demand requires significant new investments, such as new generation capacity, transmission expansion, or distribution upgrades, that are expensive. It also arises when new customers do not stay long enough (e.g., if a data center project is cancelled, a facility closes, or a customer relocates), or ramp up slowly enough, to fully use the new infrastructure, leaving stranded or underutilized assets whose costs are recovered from remaining customers. Even where spare capacity exists, new load may push the system onto higher-cost portions of the supply curve, which can offset the benefits of spreading costs.

Whether a given situation looks more like the first or second case depends on several factors:

- **System conditions:** generation mix, current average costs, demand profiles, spare capacity, investments in the pipeline, and reliability requirements, including monitoring systems, dynamic stability studies, and protection coordination.[3]

1 Utility system costs can rise with inflation, including labor-driven operations and maintenance costs and equipment replacements, which means that some upward trend in nominal rates is expected regardless of load growth. The more relevant metric is whether rates rise faster or slower than general inflation.

2 These questions also apply to interventions that lower electricity demand such as rooftop solar and energy efficiency.

3 Spare capacity has become scarce in several regions after years of relatively flat load growth followed by rapid demand increases. NERC's 2024 Long-Term Reliability Assessment projects that roughly half of North American jurisdictions could face insufficient reserve margins by 2029 (NERC, 2024).

- **Shape of new loads:** size, load factor, coincidence with net system peaks, and ability to shift or curtail demand during stress periods.
- **Technologies available to serve load:** costs and performance of new generation, energy storage, and demand-side options, including how quickly they can be financed, permitted, and built. Costs depend on siting and permitting constraints, interconnection backlogs, equipment shortages, and other supply chain bottlenecks.
- **Regulatory and market context:** in cost-of-service regions, more of the new infrastructure costs show up directly in rates; in restructured markets, more of the impact shows up in wholesale prices and contracts that large customers sign with suppliers. In both cases, the underlying economics are similar.

From an economic perspective, this question is often expressed in terms of average cost versus marginal cost. In this context, marginal should be understood as the total incremental system cost of serving additional load in the long run, including any new capacity, not just the short-run fuel and variable costs. **When that total incremental cost is below current average costs, new load tends to reduce average prices; when it is above, it tends to increase them.**[4] Importantly, the relevant comparison involves future average costs, not current ones. Many utilities are actively modernizing their generation portfolios, replacing aging coal and gas plants with new resources regardless of new demand. In this context, average costs are moving targets: new generation may be more expensive than fully depreciated capacity, but companies are building capacity to serve existing customers, and new large loads can share the costs of future investments, which can improve cost recovery.

Figure 1 provides a stylized illustration of this effect. As demand grows, average total costs per kWh (green line) initially fall as fixed costs are spread over more sales and later rise as more expensive resources and upgrades are required.[5]

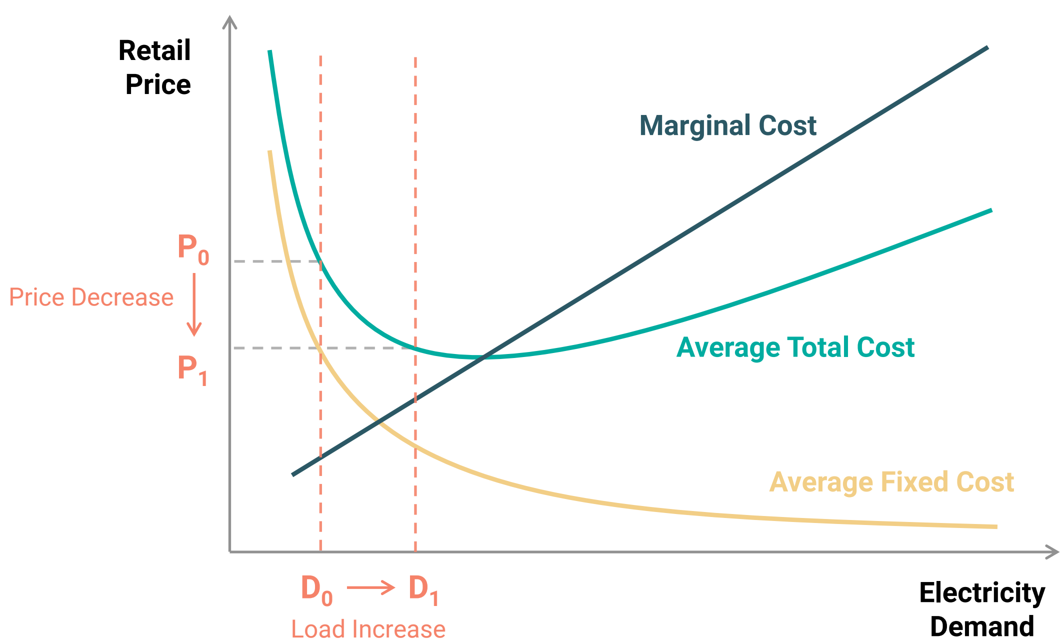

Figure 1. Stylized relationship between demand growth and average electricity costs. *At low to moderate demand, additional load helps spread fixed system costs and lowers average costs. Beyond a certain point, serving additional load requires higher-cost investments, and average costs begin to rise. Here, marginal costs represent the total incremental cost of serving additional load, including new system capacity, not just short-run fuel and variable costs.*

4 In practice, new generation often costs more than existing depreciated assets, and rapid demand growth can tighten markets further, especially with elevated equipment costs and expiring tax credits (EPRI, 2025f; King, et al., 2025).

5 The figure is meant to illustrate the canonical result from basic cost-of-service economics, not as a literal representation of specific power systems or technology mixes.

Large shares of system costs are recovered through energy charges in many jurisdictions. Loads that add kWh in those settings without driving proportionate investment can improve affordability for all customers. Loads (or behind-the-meter resources) that reduce billed kWh without reducing the utility's underlying costs can raise average prices, shift costs, and impact adoption decisions (EPRI, 2025c).[6]

These examples also set aside environmental externalities. Electrification of transport, buildings, and industry can provide large climate and air quality benefits by displacing fossil fuel use (EPRI, 2024a; EPRI, 2018; Bistline, et al., 2022), which are not reflected in the stylized curves but are important for many stakeholders.

KEY FINDING:

It is not a foregone conclusion that demand growth from data centers, electrification, and other new loads will either raise or lower retail electricity prices. Outcomes depend on:

- Whether the incremental cost of serving new load (including required generation, transmission, and distribution investments) is higher or lower than current average total costs. This depends on system-specific characteristics (e.g., base system mix, costs of the resources available to serve new load) and on characteristics of the new load (e.g., load profile and flexibility, distance to existing infrastructure).
- How costs are allocated across customer classes and whether large loads are on tariffs that fully cover their incremental costs.

The next section examines empirical evidence on when and where new loads have lowered or raised electricity prices. The remainder of the paper examines conditions for beneficial outcomes through the lens of three major areas that electric companies, policy-makers, and large-load customers can address:

1. Proactive planning (Sections 3-4): linking load growth forecasts to efficient investments, considering load shapes, timing, and system conditions.
2. Rate design and cost allocation (Section 5): creating conditions for large loads to cover their incremental costs and risks through tariff structures, contract terms, and protective provisions.
3. Demand flexibility (Sections 5.2 and 6): enabling new loads to reduce their contributions to system peaks, deferring investments and improving operations.

6 The figure focuses on overall average prices, not how costs are allocated across customer classes. Real-world rates are considerably more complex than these stylized examples. Complicating considerations are discussed in Section 5.1.

3. EMPIRICAL INSIGHTS ON LOAD GROWTH AND RETAIL PRICES

Emerging empirical work connects load growth and distributed energy resources (DERs) to retail electricity prices, though the evidence base remains limited. Wiser, et al. (2025) use state-level regressions with annual average prices from EIA Form 861 between 2019 and 2024. The analysis finds that **states with faster load growth generally experienced smaller price increases, or even price declines, while states with flat or falling sales tended to see larger price increases** (Figure 2). Across model variants, the load growth coefficient is stable and statistically significant with a 10% load increase associated with a 0.6±0.1¢/kWh reduction in average prices (in real terms).

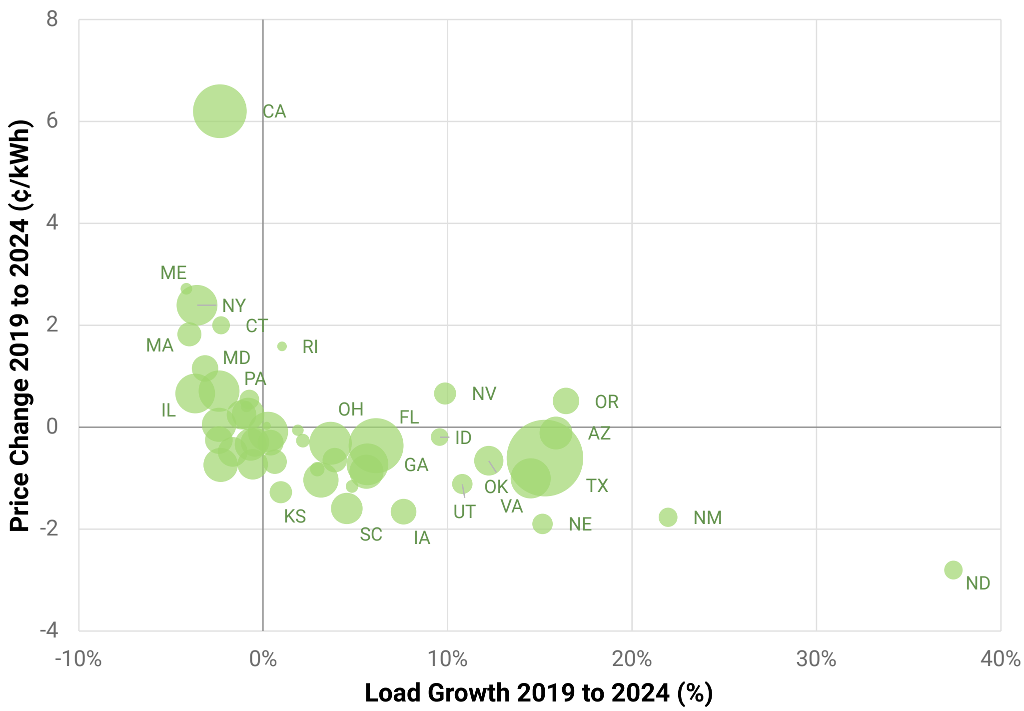

Figure 2. Relationship between load growth and changes in retail electricity prices from 2019 to 2024 (in real terms). *Note that this figure is correlational: new commercial and industrial loads have incentives to site in places where expectations of future costs are favorable. Based on data from Wiser, et al. (2025).*

Caveat: large loads tend to locate where electricity costs are favorable, so this relationship may reflect site selection as well as cost-spreading effects. That said, this pattern is consistent with the fixed-cost dynamics emphasized in this paper.

Research indicates that transmission and distribution expenditures are primary drivers of recent cost increases for many parts of the country, which have often been driven by refurbishment of existing infrastructure rather than serving new demand (Forrester, et al., 2024; EPSA, 2025). This suggests that fixed-cost dynamics could be important in these regions; when system costs are recovered through volumetric charges, higher demand tends to reduce average prices. Wiser, et al. (2025) also find that the negative correlation between load growth and prices is smaller when focusing on residential prices, underscoring the importance of how costs are allocated between large, non-residential customers and households.[7]

7 Declining generation costs over the past decade likely reinforced this dynamic by keeping marginal costs below average total cost in many regions, though the phase-down of federal tax credits could temper this effect going forward (King, et al., 2025; Bistline, et al., 2023).

The same analysis finds that growth in behind-the-meter solar has generally put upward pressure on average prices, primarily because fixed utility costs are spread over a smaller volume of billed kilowatt-hours. Between 2019 and 2024, Wiser, et al. (2025) estimate that behind-the-meter solar increased average prices by less than 0.5¢/kWh in about 40 states, but by up to ~2¢/kWh in a small set of high-penetration states (including California). They indicate that impacts are highly state-specific and are driven by rate design and compensation structures, especially when fixed costs are recovered largely through volumetric charges.

Complementing this work, Dong, et al. (2025) use utility-level data from 1990-2022 paired with an electricity generation model to study how changes in residential electricity consumption affect average residential rates. They estimate that higher residential electricity use is associated with lower residential prices, with an elasticity of about -0.4 (a 10% increase in sales is linked to a 4% drop in prices), again reflecting substantial system costs recovered through per-kWh charges. Applying this elasticity to scenarios for rooftop solar (which reduces billed kWh) and electric vehicles (which increase kWh), they conclude that, in the short run, rooftop solar tends to raise residential prices and disproportionately burden low-income non-adopters, while EV adoption reduces average prices and can benefit low-income non-adopters by lowering electricity expenditure shares. An important caveat is that the paper largely reflects the short-run effect of weather-driven load variation under volumetric rate structures, rather than estimates of how structural changes in demand affect long-run retail prices.

Empirical work linking load changes to retail prices is still limited, and most evidence comes from case studies and modeling rather than long-run causal estimates of load-price relationships.[8]

KEY FINDING:

Empirical and modeling studies suggest load growth can meaningfully moderate average price increases, but the direction and distribution of price impacts depend heavily on rate design, cost recovery mechanisms, and how new loads interact with system planning.

8 For example, Carvallo, et al. (2021) use integrated generation, transmission, and distribution expansion modeling to show that portfolios of DERs, including rooftop solar, EVs, and energy storage, can either increase or decrease long-run system costs and retail rates depending on siting, load shapes, and rate structures.

4. LOAD SHAPE AND PLANNING IMPLICATIONS OF NEW LOADS

The effects of data centers and other new loads on power system investments, operations, and costs depend on load shape changes. Different loads vary in their hourly profiles and timing relative to system peaks. Future impacts are uncertain due to more limited experience with novel loads, differences across projects and households, and influence of rate design.

Data centers, especially ones supporting AI workloads, are often expected to operate with relatively flat hourly profiles. However, load characteristics vary considerably by workload type. AI training workloads, in particular, maintain sustained high utilization during active training runs but may exhibit more volatility between runs and across facility lifecycles. Realized load can also fall below nominal capacity, especially as servers and other equipment are added over time and facilities ramp up to full utilization or business conditions change. AI inference workloads, which serve real-time queries, tend to exhibit different temporal variation.

Load shapes for non-data-center loads vary by end use and region. EPRI modeling shows how these load profiles differ over time, across regions, and under different technology and policy scenarios (e.g., if electrification is driven by mandates versus economic adoption). Figure 3 contrasts the profiles for a cold weather region (which has strong seasonal dynamics from space heating) and a warmer climate (which is dominated more by seasonal cooling demand), though both regions exhibit prominent demand from EV charging due to the competitiveness of transport electrification.[9]

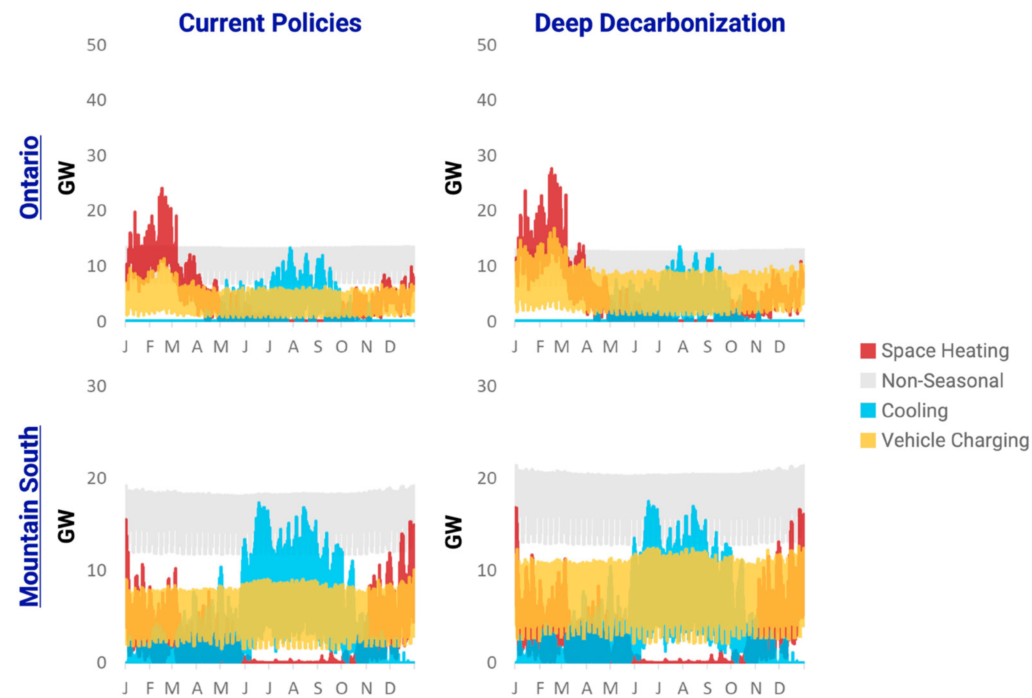

Figure 3. ***Hourly load profiles by end use across policy scenarios (columns) and regions (rows) in 2050.*** *Non-seasonal loads include all non-space-conditioning loads in buildings and industry. Source: Adapted from Bistline, et al. (2021).*

Load factor is the ratio of average demand to peak demand. It measures how efficiently the capacity of the system is used. High load factors mean steady utilization, while low load factors imply spiky demand and idle capacity between peaks. As the resource mix includes greater shares of solar and wind, the value of different load shapes depends increasingly on their timing relative to low-cost generation periods.

9 EPRI's Load Shape Library is a data platform and repository for end use and building load profiles: https://loadshape.epri.com/.

Electric companies recognize the value of high-load-factor customers in rate design, because they can impose lower per-unit costs on the system by:[10]

- Utilizing infrastructure capacity more fully;
- Providing more predictable loads that simplify system planning; and
- Requiring proportionally less standby capacity.

The current U.S. electricity system operates at approximately 55% load factor on average today in contrast to data centers, which are typically modeled or treated as high-load-factor customers, often in the 70-90% range of operational capacity, with some studies and tariffs assuming values around 85-90% for large hyperscale facilities (Frick and Srinivasan, 2025).[11] Modeled scenarios in Figure 4 suggest that electrification can increase or decrease average load factors depending on the regional climate, winter-to-summer peak ratio of the current system, and shares of specific electrification technologies (including the backup source for electrified space heating).

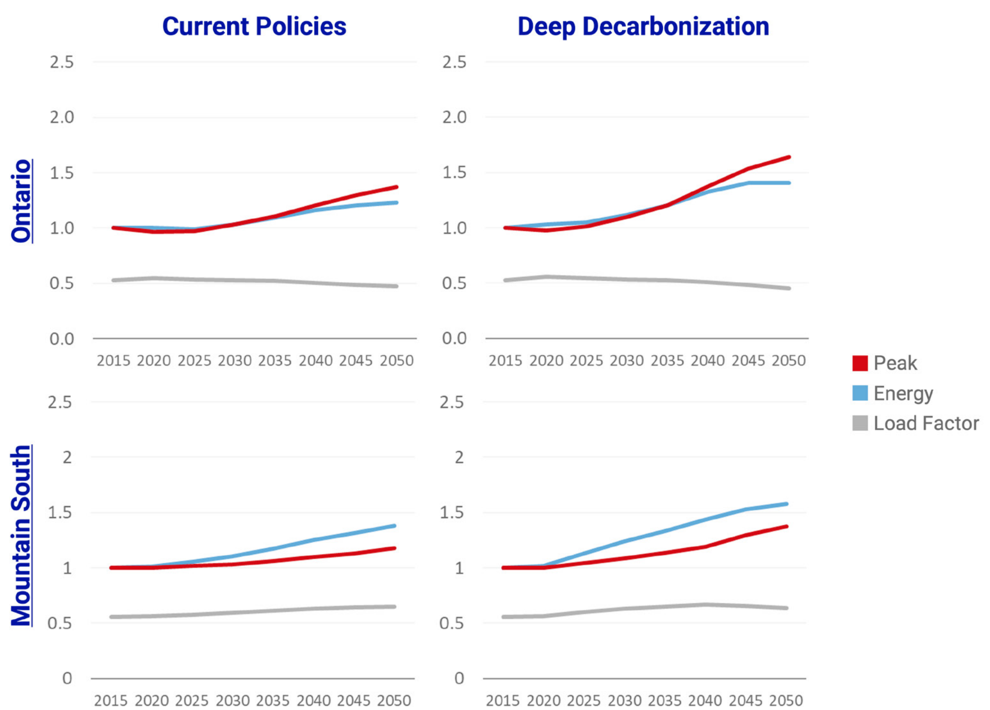

***Figure 4.* Normalized energy, peak, and load factors across policy scenarios (columns) and regions (rows) over time**. *The system load factor is the ratio of the average load to peak load. Source: Adapted from Bistline, et al. (2021).*

Large loads also can create economies of scale that benefit the broader system. When generation and transmission are built to serve data centers and other large loads, they may achieve lower per-unit costs than would be possible with small, incremental additions.

Flexible demand resources can facilitate the integration of new loads and reduce electric sector costs of growing load. Flexible charging can move EV loads into lower-cost periods. Idle vehicles and spare charging capacity mean that EV charging may be more flexible than other end uses (EPRI, 2022). However, a range of behavioral, economic, and

10 These benefits assume available capacity. In capacity-constrained systems, new demand with high load factors may trigger expensive peaking resources or new generation and transmission at costs exceeding current averages, potentially reversing expected benefits.

11 These planning assumptions, however, may not always match operational conditions in specific markets, as actual utilization can vary by facility age, scale, workload type, and business conditions.

technological factors impact whether transport electrification can alleviate or intensify peak demand. Field experiments indicate that EV owners strongly respond to financial incentives and shift to low-cost hours, depending on retail rate design, opportunity costs of time and effort, and system characteristics (EPRI, 2024c; Bailey, et al., 2026; Bailey, et al., 2025a; Bailey, et al., 2025b). Recent studies suggest that charging flexibility can induce greater emissions reductions from transport electrification (Bhandarkar, et al., 2025; Chen, et al., 2025).

Data center flexibility can avoid periods of system strain and large infrastructure buildout, which could be incentivized by faster grid connections (EPRI, 2025d). Field experiments demonstrate reductions in cluster power usage during grid stress events (Colangelo, et al., 2025).

Assumptions about load shapes and flexibility ultimately impact electric sector planning, which may entail additions of new resources, not just operational changes, even if loads are flexible. **Growing loads may encourage greater deployment of low-emitting resources, including renewables, nuclear, energy storage, and CCS-equipped capacity, especially given clean energy commitments of technology companies and electric companies** (EPRI, 2024d; EPRI, 2023). Policy incentives and declining technological costs, especially solar and battery storage, meant that low-emitting resources were over 90% of new additions in the U.S. in 2024.

In addition to accelerating clean energy adoption and lowering emissions, growing loads may accelerate the deployment of emerging technologies such as advanced nuclear, CCS, enhanced geothermal, and long-duration energy storage, especially given 24/7 carbon-free energy commitments of companies like Google and revisions to the Greenhouse Gas Protocol that emphasize temporal matching (EPRI, 2024e). In January 2026, Meta announced 20-year agreements that would support up to 6.6 GW of nuclear energy by 2035, including from small modular reactors. Energy systems modeling suggests that impacts are highly scenario- and region-specific (EPRI, 2024d; Bistline, et al., 2025; Bistline, et al., 2024).

KEY FINDING:

Meeting growing load affordably, reliably, and sustainably requires proactive planning, which can leverage growth in important emerging sectors (AI demand, electrification, manufacturing) while scaling innovation in another (clean energy). Flexible demand resources can facilitate the integration of new loads and reduce electric sector costs of growing load.

5. TARIFF DESIGN: THEORY AND PRACTICE

5.1. Rate Design Challenge

Tariffs define a utility's retail electricity rates and terms of service for applicable customer classes and are filed with state regulatory commissions or municipal jurisdictions through public proceedings.

Utilities and regulators often create special large load tariffs or negotiated agreements to attract new customers. If these arrangements are priced so that new customers at least cover the incremental costs and risks they impose on the grid, other customers can share in the benefits of lower average costs or at least avoid adverse impacts. If new large loads are underpriced or do not adequately protect against underutilization or early exit, existing customers could see higher costs.

A key consideration for utilities and regulators in designing tariffs for new large load customers is mitigating the risk of other ratepayers bearing costs associated with connecting these new loads. Safeguard provisions include minimum contract terms (to better match contract duration with asset lifecycles), minimum monthly billing demand, collateral and fiscal security requirements, exit fees, and capacity reassignment.[12]

These provisions aim to protect other customers from cost shifting and from absorbing the costs of infrastructure built for large loads that do not materialize or exit early (i.e., stranded asset risk). Even when system-wide costs decline on a per-unit basis, cost allocation methodologies may prevent these benefits from flowing to existing customers. Technology risk adds another dimension, including rapid gains in chip efficiency or shifts in compute architecture that may reduce electricity demand per unit of computation, which could leave infrastructure underutilized. This may reinforce the case for minimum billing provisions and accelerated depreciation to address stranded asset risk.

Tariffs for large loads typically combine three billing components:

- **Energy charges**, also called "volumetric charges," are the product of a customer's monthly energy consumption (kWh) and applicable $/kWh rate, which may be uniform or time-varying.
- **Demand charges** are typically based on a customer's monthly peak power demand (kW) or demand coincident with system peaks.
- **Fixed charges** are monthly customer charges that cover costs like metering and billing that largely do not vary with electricity usage or peak demand.

Designing pricing structures for large-load customers requires balancing billing components, rate design choices, time-dependence, and policy objectives. The goal is a tariff that serves the public interest with the following characteristics:[13]

- **Economically sound**: providing necessary cost recovery;
- **Affordable and competitive**: facilitating customer retention and economic growth;
- **Aligned with broader societal goals**: providing incentives for efficiency, flexibility, emissions reductions, and reliability; and
- **Fair**: avoiding undue cross-subsidies between large loads and other customers as well as transfers within classes.

Rate design determines how the benefits of load growth, if any, flow to different customer classes. For many residential and commercial customers, fixed costs are recovered substantially through volumetric charges; in this setting, spreading fixed costs over more kilowatt-hours can reduce average prices. For large load customers, utilities often recover fixed costs

12 Even with extended contract terms, asset lifecycle risk remains a consideration. Generation and transmission assets can have useful lives of 30-50 years, so a 15-year contract may only cover a fraction of this period. Tariff structures that incorporate accelerated depreciation, amortizing dedicated infrastructure costs within the contract term, and other approaches can help to address this mismatch.

13 For foundational treatments of rate design principles, see Bonbright's "Principles of Public Utility Rates" and Garfield and Lovejoy's "Public Utility Economics."

through demand charges (based on peak kW) with minimum billing provisions structured around contracted demand. This approach can provide appropriate price signals and aligns cost recovery with infrastructure requirements that large loads impose.

Several jurisdictions have moved toward higher fixed charges and lower volumetric charges to encourage electrification and reduce bill volatility (EPRI, 2025c). This trend can reduce the potential for load growth to lower average prices, but it also strengthens price signals for electrification and can ease concerns about cost shifting from behind-the-meter resources. Policy-makers and regulators are actively debating these tradeoffs, especially as they relate to energy efficiency, rooftop solar, and emerging large loads like data centers.

5.2. The Role of Demand Flexibility

Flexible loads that curtail demand during grid stress can defer infrastructure investments that would otherwise be recovered from all ratepayers, a direct benefit to affordability.[14] Traditional tariff structures such as interruptible, curtailable, standby, and demand response (DR) rates provide credits to customers willing to reduce loads when needed to avoid coincident peak demand at the nodal or system level. EPRI's literature review of tariffs for large-load customers suggests that compensation is generally tied to the extent and responsiveness of flexibility commitments (Figure 5).[15]

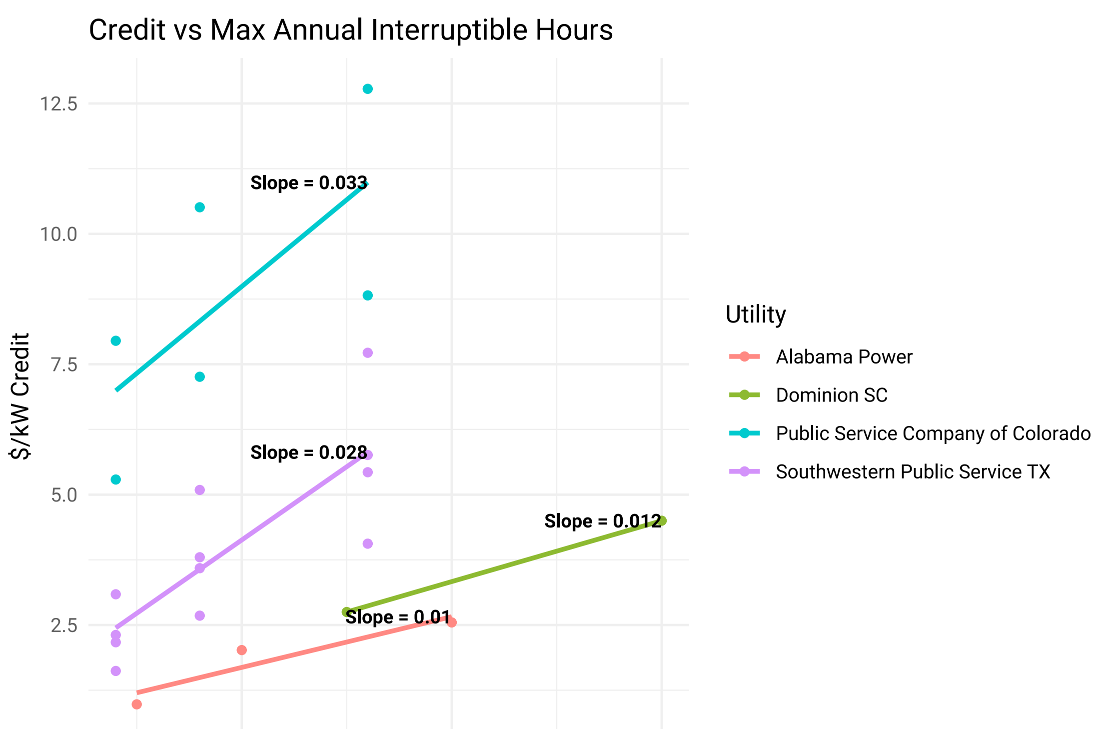

Figure 5. Selected rate credits on interruptible tariffs as a function of maximum annual interruptible hours*. Source: EPRI (2025e). Note that the relationships in this figure are based on a subset of tariffs and simple correlations, so the coefficient and credit values are not necessarily representative of all utilities and may be influenced by other tariff design features.*[16]

14 EPRI's DCFlex field experiments have demonstrated that AI data centers can reduce cluster power usage by 10-20% during peak grid events with minimal disruption to operations (Colangelo, et al., 2025), which can defer or avoid generation and transmission investments that would otherwise be needed to meet coincident peak demand.

15 EPRI has reviewed metrics germane to grid-responsive DR, including notification periods, interruption triggers, maximum annual hours of interruption, event frequency, event duration, and customer credits (EPRI, 2025e). The advance notification prior to an interruption event across all such types of tariffs typically ranges from 15 minutes to 2 hours. DR rates tend to offer higher credits, with some as high as $100/kW. The higher the maximum annual interruptible hours specified in a tariff the greater the customer credits, with a positive correlation ranging from $0.01 to $0.03 per kW.

16 The main takeaway is the direction of the relationships (i.e., how credits vary with allowable interruption hours and notice periods) rather than the specific dollar values.

Both relationships reinforce the notion that utilities assign higher value to more curtailable hours with shorter notification periods in response to grid conditions. Although load interruptibility can serve as a bridging mechanism while new assets are planned and constructed, flexible loads cannot indefinitely substitute for new capacity in many contexts. The value of additional interruptible hours diminishes as curtailment requirements move beyond peak periods.

Achieving this potential requires demonstrating that data center flexibility can be delivered without disrupting core operations. EPRI's DCFlex initiative (Section 6) provides timely information by testing practical approaches to data center flexibility through shifting workloads, leveraging backup systems, and integrating on-site resources. DCFlex is creating the evidence base needed to design tariffs and interconnection processes that turn growth into grid assets.

5.3. Real-World Solutions

This framework is being tested in practice through several deals and regulatory actions across the U.S. These cases provide lessons about protecting ratepayer affordability while enabling development of data centers. Table 1 below lists eight tariffs categorized as "Data Center Rates" that apply exclusively to data centers or crypto-mining customers (EPRI, 2025e), which incorporate some degree of load flexibility.

Table 1. Sampling of tariffs specific to data centers as distinct customer class. *Source: EPRI (2025e). See EPRI's DCFlex tariff tracking initiative for a more complete database.*

Utility	Rate	Load Flexibility
AEP OH	Data Center Tariff	BTM gen. must be interruptible
Cheyenne Light Fuel & Power	Blockchain Interruptible Service	Interruptible
Cheyenne Light Fuel & Power	Large Power Contract Service	BTM gen. required, dispatchable by utility
Entergy AR	Large Power High Load Density Service	Interruptible
Idaho Power	Speculative High Density Load	Interruptible
Idaho Power	Schedule 33 ESA for Brisbie data center	None
Montana-Dakota Utilities	High Density Contracted DR	Demand Response
Portland General Electric	Data Center Standard Service	Ongoing Proceeding UM 2377

In addition to Data Center Tariffs, EPRI is tracking new tariffs being developed for large load customers. While data centers may qualify for these tariffs, they are not explicitly specified (EPRI, 2025e).

In January 2026, Microsoft announced a "community-first" approach to AI data center development, committing to pay electricity rates sufficient to cover incremental grid investments, forgo local tax abatements, and address water impacts (Microsoft, 2026). This development illustrates how large customers can proactively reduce cost-shifting concerns and make rapid local growth more sustainable.

EPRI's DCFlex initiative is tracking pertinent metrics on proposed and approved tariffs such as these for data centers and large load customers, including elements such as contract term length, minimum billing demand, collateral requirements, exit fees, and other requirements. Minimum Billing Demand (also known as Minimum Take-or-Pay) is a common large load tariff element designed to address risk by helping to ensure a certain level of revenue is recovered from large load customers, regardless of usage.

EPRI's DCFlex initiative also monitors state regulatory and legislative developments related to tariffs and flexibility programs for large customers, including those explicitly citing data centers as a distinct customer class.

Georgia PSC: Mandatory Incremental Cost Recovery

The Georgia Public Service Commission accepted ratepayer protection rules in early 2025 (GPSC, 2025) that include:

- **Threshold trigger**: any new customer using more than 100 megawatts (MW) must be billed under special terms beyond standard customer rates.
- **Progressive cost recovery**: data centers must pay transmission and distribution costs as construction progresses, not after the fact.
- **Upstream infrastructure costs**: large customers bear full costs for generation, transmission, and distribution infrastructure required to serve them.
- **Contract length requirements**: extended contract terms (up to 15 years, versus typical 5-year contracts) ensure cost recovery even if projects shut down early.
- **Oversight**: all contracts with customers exceeding 100 MW must be submitted to the PSC for review within 30 days.
- **Minimum billing requirements**: large customers face minimum bills even if electricity usage fluctuates, preventing cost-shifting to other ratepayers.

These rules aim to mitigate the stranded cost risks identified earlier. The 15-year contract and minimum billing both aim to lower ratepayer risk if a data center fails to materialize or closes earlier than expected.

Entergy-Meta: Largest Private Investment in Louisiana History

In Meta's largest global facility at the $10 billion AI data center in Richland Parish, Louisiana, Entergy adopted a different approach where it took a leading role in economic development (Entergy, 2024). The Entergy deal includes:

- **Dedicated generation**: three new gas-fired power plants totaling 2.26 GW, with two units online by 2028 and a third by late 2029.
- **Meta-funded substation**: the 55-acre Smalling Substation entirely funded by Meta (estimated hundreds of millions of dollars).
- **15-year revenue guarantee**: Meta pays full annual revenue for the plants for 15 years, providing revenue certainty for infrastructure investment.
- **Renewables pledge**: Meta commits to offset its electricity consumption by procuring renewable energy credits equivalent to 100% of its usage through at least 1,500 MW of new clean energy capacity via Entergy's "Geaux Zero" program. This is separate from the dedicated gas-fired generation, which provides firm capacity for the facility.
- **Community funding**: up to $1 million annually to Entergy's "The Power to Care" low-income ratepayer support program (matched by Entergy).

Entergy CEO Drew Marsh said that Meta will become Entergy's largest customer (Goldman, 2025). The Louisiana Public Service Commission approved the arrangement 4-1 in August 2024. However, environmental groups challenged the approval process, arguing Entergy circumvented proper procedures for proposing natural-gas-fired power plants that could burden other ratepayers.

We Energies: Very Large Customer and Bespoke Resources Tariffs

Wisconsin Electric Power Company (We Energies) proposed two new, interrelated tariffs: the Very Large Customer (VLC) Tariff and the Bespoke Resources Tariff (BRT), which would serve new large loads of 500 MW or more, including data centers. The tariffs are designed to facilitate the economic development provided by these large loads, while also ensuring all incremental costs, risks, and investments required to serve these customers are fully borne by them and not shifted to existing customers or shareholders.[17]

The VLC Tariff establishes the retail service and billing frameworks for eligible customers, while the BRT governs customer-specific resources built to serve that load. Together, the tariffs offer a specialized rate treatment designed to isolate the costs to serve these large loads.

The VLC Tariff features an initial contract term of 10 years, with minimum billing requirements and direct cost allocation terms that ensure full cost recovery regardless of monthly usage. Enhanced credit and collateral requirements aim to protect against non-payment risk during construction and operation. Upon termination, the customer is responsible for the remaining undepreciated book value of the dedicated assets, unless repurposed with Commission approval. This all helps protect against risk of stranded abandoned assets.

NIPSCO-Amazon: Balancing Speed and Affordability

In November 2025, Northern Indiana Public Service Co. (NIPSCO) announced that it signed a long-term contract to serve Amazon data centers in northern Indiana. This new load of 2.4 GW by 2032 is comparable to NIPSCO's entire non-data-center load (NiSource, 2025). To serve this load, NIPSCO is using an affiliate, called NIPSCO Generation (GenCo), to invest $7 billion in 3 GW of dispatchable generation and energy storage alongside transmission investment. The announcement highlights that the GenCo structure can avoid shifting major infrastructure costs onto existing customers and that an estimated $1 billion in cost savings would be returned in customer credits during the project's 15-year duration. The NIPSCO-Amazon agreement is a live example of potential "win-win" conditions where large, high-load-factor customers can support affordability and grid investment, if incremental costs are managed and existing customers are shielded from risk.[18]

Taken together, these examples illustrate how the three major areas – proactive planning, rate design, and demand flexibility – can support beneficial outcomes, including lower prices, improved utilization, clean energy acceleration, and lower emissions. These case studies also illustrate how real-world solutions vary across contexts and may not be generalizable across domains. Ultimately, achieving the full range of beneficial outcomes will require context-specific integration all three areas for how new loads are planned, priced, and operated.

17 This is intended to comply with Wis. Stat. § 196.192. Note this is a unique proposal developed jointly with Microsoft to serve a data center in We Energies service territory. The proposal has not been approved by the Wisconsin Public Service Commission. A decision in Docket 6630-TE-113 is due May 1, 2026.

6. EPRI'S DCFLEX INITIATIVE: TRANSFORMING DATA CENTERS INTO GRID ASSETS

Earlier sections highlight the net impact of new data center load on retail prices depends not just on size and load factor, but also on incremental infrastructure needs and the ability of new loads to flex during system peaks. **EPRI's Data Center Flexible Load Initiative (DCFlex) operationalizes this "flexibility lever," demonstrating how high-load-factor data centers can support reliability and affordability** instead of driving up peak demand and investment.

Launched in 2024, DCFlex brings together a global coalition of hyperscalers, electric companies, grid operators, and data center developers to test practical strategies for making large loads flexible. The initiative focuses on three main areas: 1. Computational flexibility, such as shifting non-time-critical AI and cloud workloads away from higher-cost periods; 2. Leveraging existing backup generation and energy storage systems to ride through disturbances and ease strain on the grid;[18] and 3. Better integration of behind-the-meter resources, including on-site generation, so they can provide business continuity and grid services.[19]

DCFlex directly complements the economic logic discussed in earlier sections. By enabling data centers to maintain high average utilization while providing targeted flexibility during the relatively small number of hours when systems are stressed, DCFlex helps reduce incremental capacity needs, improve utilization of existing assets, and support renewable integration. In doing so, it increases the likelihood that the theoretical benefits of high-load-factor growth (i.e., lower average costs and moderated rate impacts) can be realized in practice, provided that rate design and cost allocation are structured so these benefits are shared with other customers.

18 Large data centers' uninterruptable power supply systems also may offer opportunities for short-term grid stability beyond ride-through capability. During frequency excursions, data centers that remain grid connected and use on-site energy storage to adsorb or inject power could help suppress frequency deviations, which could be valuable in systems with limited inertia (e.g., due to high inverter-based resource deployment).

19 On-site power and demand flexibility can be complementary approaches for reducing a data center's draw from the grid during critical periods, whether by substituting local generation or by temporarily reducing demand. Regulatory frameworks can affect how much flexibility data centers can provide, including interconnection rules, standby tariffs, and air quality permits.

7. SYNTHESIS: CONDITIONS FOR BENEFICIAL OUTCOMES

This paper shows that the impact of new load on average electricity prices is ambiguous. High-load-factor growth from data centers, electrification, and new industrial activity can either moderate or increase average prices, depending on system conditions, load characteristics, technology costs, and rate design. Because many U.S. retail tariffs recover a large share of fixed costs through volumetric charges, the central question is whether the incremental cost of serving new load is higher or lower than current average costs, and how these costs and benefits are allocated across customer classes.

Recent economic and modeling work suggests meaningful scope for beneficial outcomes. States with faster load growth in recent years have often seen smaller price increases or modest reductions, consistent with fixed costs being spread over more kilowatt-hours. However, practical constraints such as scarce spare capacity, rising costs for new generation in tight markets, uncertain developer willingness to provide flexibility, and risk of cost shifting mean that favorable outcomes are far from guaranteed.

These findings highlight conditions under which growing load can support affordability while advancing clean energy and reliability goals:

- **Incremental costs below average costs**, due to spare capacity or relatively low-cost expansion options for generation, transmission, and distribution. This condition is more likely to hold in higher-cost systems, where current rates already reflect recent investments and new resources may be cost-competitive. It is less likely in lower-cost systems, where serving large new loads may require substantial new investments at costs well above current averages.
- **High and predictable utilization**, so new loads (especially data centers) support efficient planning rather than creating large gaps between contracted and realized demand.
- **Data availability and baseline transparency**, so grid operators and electric companies can evaluate data center flexibility in planning and operations. Data center operations can be opaque (Masanet, et al., 2024), yet incorporating flexibility into planning requires evaluation of baseline profiles and flexible capabilities.
- **Favorable load shapes and flexibility**, so new demand either flattens the system profile or, through price-responsive demand, reduces its contribution to coincident peaks. In capacity-constrained environments, flexibility is important in achieving beneficial outcomes. Whether data center developers will accept tradeoffs between speed-to-power and flexibility is a key question, and initiatives like DCFlex can demonstrate what is operationally feasible.
- **Well-designed tariffs and cost allocation**, so large-load customers cover the incremental costs and risks they impose and are compensated for flexibility in ways that reflect the system value they provide.

Proactive planning, robust safeguards in large-load tariffs, and explicit incentives for demand flexibility, including initiatives like EPRI's DCFlex, can help turn high-load-factor growth into a tool for moderating average prices, improving asset utilization, and accelerating clean energy deployment.

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3002034619 **January 2026**

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