Memo: Grid Impacts of High Load Factor Load

February 2026

Introduction and background

U.S. electricity demand forecasts have been revised upward sharply in the last several years, and recent planning-entity projections increasingly identify data centers as a primary driver of near-term load and energy growth. Data center demand is already a significant feature of today's grid, with total installed data center capacity estimated at over 50 gigawatts (GW).[i] Additionally, this number is dwarfed by projected future additions: aggregated utility forecasts indicate that an additional 90 GW of data center demand will seek power over the next five years alone.[ii] Against a backdrop of rising electricity bills and intensifying focus on energy affordability, stakeholders are scrutinizing the extent to which data center load growth could affect retail rates.

Data centers are usually high load factor (HLF) loads, meaning their average demand is high relative to their peak demand. Over a specific time window, load factor can be expressed as total energy consumed over the period divided by the product of the period's peak demand and the number of hours in the period. While there is no uniform industry standard for what qualifies as HLF, thresholds often fall in the 70%–95% range. Because load factor affects energy consumption relative to peak demand, it can influence both resource adequacy and the utilization of delivery infrastructure but does not, by itself, describe volatility, ramp rates, contingency behavior, or coincidence with the system peak, each of which may be material for planning and operations.[1]

HLF loads are often discussed as "good for the system" because, under certain conditions, increased utilization of existing infrastructure spreads fixed costs over more usage (kWh).[iii] This memo introduces conditions under which HLF loads can reduce rates, discusses real-world examples of that dynamic, then covers caveats and scenarios in which HLF loads may increase rates. Finally, the memo describes how cost allocation policy effects how HLF loads impact rates and introduces open questions around the impacts of HLF loads on the grid.

Conditions under which HLF loads can reduce rates

Many industries, including all regulated natural monopoly industries with public utilities, have high fixed costs that must be paid regardless of how much customers use the system. When additional volume can be served using existing capacity ("headroom"), higher utilization can lower average costs by spreading those fixed costs across more output; classic examples include railroads (track and network infrastructure), pipelines (pipe and compressor systems), and telecom networks (fiber and switching equipment). This logic applies to the electric sector because utilities recover large capital and capacity costs through regulated rates, and additional load can reduce average costs when it can be served without major new investment.

In cost-of-service regulation, which is widely used in the electric sector and other regulated public utility industries, rates are designed to recover approved revenue requirements associated with generation

[1] Note that the size of current data center developments almost always requires connection at transmission voltage. Relatively small data centers connected to distribution systems are most likely to materially affect the distribution system rather than the generation and transmission systems.

capacity, transmission and distribution facilities, and supporting operations. If new load can be served largely with existing system capability, or with only modest marginal investment, incremental kWh sales can improve utilization of sunk assets and spread fixed costs over more units of energy sold and over more customers, alleviating some of the cost burden. Under these conditions, average cost per kWh and average retail rates can decline, all else equal.[iv]

HLF loads are frequently central to this argument because they contribute a relatively large volume of sales relative to peak demand over the measurement window. Put differently, for a given peak demand contribution, higher load factor implies more usage (kWh) over the billing period, which can increase the billing determinant base used to recover those fixed costs that are recovered volumetrically.[v]

Analyses of large-load integration emphasize that affordability impacts depend not only on the magnitude of new energy consumption, but on how new demand aligns with constrained hours and locations. Load flexibility or operating practices that reduce contributions to peak conditions, shift consumption to periods of available capacity, or avoid exacerbating locally binding constraints can reduce the need for incremental procurement and delivery investments. These attributes are analytically distinct from load factor itself, but can be complementary where present and can materially affect whether incremental load can be served with modest marginal investment.[vi]

Empirical support for beneficial rate effects of HLF loads

Recent work by Berkeley Lab suggests that, in some states, load growth has been associated with downward pressure on average retail electricity prices, consistent with the mechanisms discussed above. For example, the report identifies North Dakota, New Mexico, and Nebraska as cases in which average retail prices declined notably 2019–2024, attributing the decline in significant part to substantial growth in commercial and industrial load together with abundant supply conditions over the period.[vii] In state-level analysis, a prior report finds that increases in statewide load are associated with reductions in overall average prices, holding other factors constant, while emphasizing that the relationship need not hold in tighter supply environments.[viii]

In ERCOT, recent public reporting similarly highlights how growing energy use can moderate average cost metrics even as total investment rises. In a February 2026 CEO update to ERCOT's Board, ERCOT shows that Transmission Cost of Service (TCOS) increased over the 2015–2024 period (Figure 1) while TCOS per total MWh energy use ($/MWh), adjusted for inflation, trended flat to declining (Figure 2), as overall energy use continued to grow.[ix]

Figure 1: ERCOT Region Annual TCOS ($ Billion)

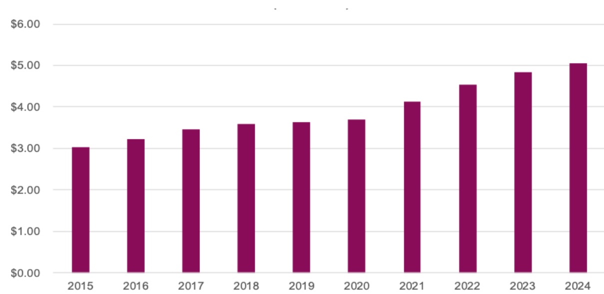
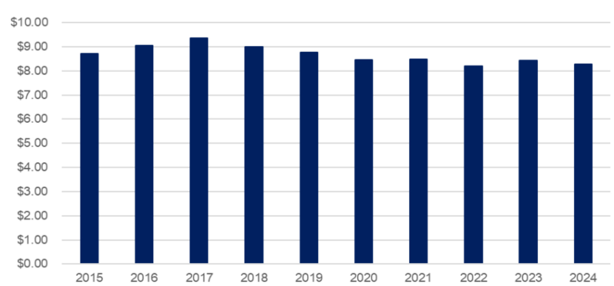


Figure 2: ERCOT Region Annual TCOS per Total MWh Energy Use ($/MWh)



Utilities and regulators have observed the linkage between incremental large-load revenue to customer bills. PG&E, for example, has stated that for every additional 1,000 MW (1 GW) of new electric demand from data centers that it serves, PG&E customers may save roughly 1–2% on monthly bills in the long term, because added revenues can help offset a substantial multi-year capital investment plan.[x] In Georgia, public reporting quotes Georgia Public Service Commission Chairman Jason Shaw crediting revenue from large-load customers as enabling the state's ability to freeze Georgia Power base rates for a multi-year period.[xi]

Where HLF loads might increase rates

The fixed-cost spreading logic described above does not necessarily hold when serving new load requires material incremental costs that are large relative to the system's current average cost, or when those costs must be incurred ahead of realized load. Incremental cost drivers can include

- new generation capacity additions and associated financing, fuel, and purchased-power costs;
- transmission and distribution upgrades needed to deliver power to the interconnection point;
- interconnection-related network upgrades; and
- accelerated replacement or hardening investments, where load growth interacts with broader infrastructure needs. [xii]

As these costs enter rates, the net effect on other customers depends on how they are assigned, as discussed in the next section.

The marginal cost of serving a new large load is often determined by local constraints on the delivery system. Limits at a particular substation, feeder, local transmission element, or protection and voltage condition can trigger significant, lumpy (large, discrete, and not easily scaled incrementally) upgrades with long lead times.[xiii] These costs can be especially consequential when utilities must build infrastructure ahead of realized load to meet energization schedules, because the resulting capital spending can create carrying and financing costs during the construction period and can place new plant into rate base before associated revenues are fully realized.[xiv] If the load is delayed, reduced, ramps more slowly than expected, or does not materialize, utilities may also face stranded-cost risk, which can translate into upward pressure on rates unless mitigated through contractual and tariff provisions.[xv]

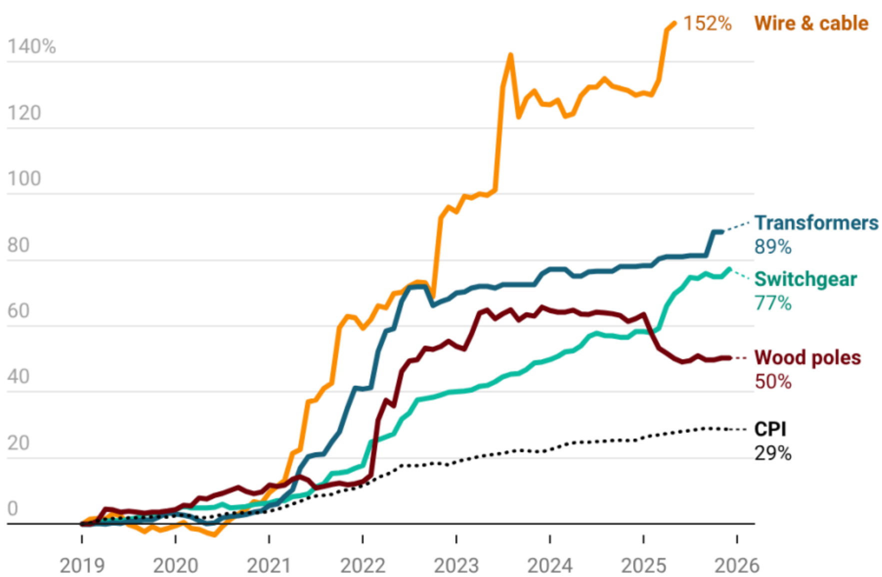
Recent work by Berkeley Lab underscores that the relationship between load growth and average retail prices is not uniform and can vary materially across states and over time. In the state-level analysis of retail price trends discussed above, the authors emphasize that relationships observed in recent history may change in the future and note that the association between load growth and lower average prices need not hold in tighter supply environments.[xvi] Berkeley Lab's most recent report calls out PJM's recent capacity price spikes as an example of load growth, in the context of constrained supply, driving significant price increases.[xvii] In tighter supply environments, the risk of upward pressure on rates is amplified when new generation and transmission needed to serve load growth is delayed, because near-term reliability needs must still be met and scarcity conditions can elevate capacity and energy costs. Generator interconnection backlogs and slow study timelines can delay the entry of new supply, reduce competitive pressure, and increase reliance on higher-cost resources or procurement outcomes.[xviii] Similarly, delays in permitting and developing transmission can postpone delivery of lower-cost resources and other system benefits, increasing total system costs during the delay period because the forgone benefits are not recaptured retroactively.[xix]

A further pathway for upward pressure on rates is escalation in the cost of critical grid equipment and associated construction, which increases the capital cost of upgrades needed to serve new load. Prices for key components, particularly transformers and switchgear, have increased materially relative to pre-pandemic levels, reflecting supply chain constraints, higher input costs, and strong demand for grid expansion.[xx] As a result, the incremental cost of serving new load may exceed historical average costs embedded in rates, increasing the likelihood of upward pressure on revenue requirements and, ultimately, customer bills.

Figure 3: Producer Price Index for Power System Equipment

Source: LBNL. *Retail Price Trends: 2026 edition*. March 2026.

Shown as percentage change relative to January 1, 2019, also compared to CPI



Rate design implications

The extent to which new large loads reduce or increase retail rates depends not only on system conditions and incremental investment needs, but also on the basic rate construct used to recover utility costs. In cost-of-service regulation, utilities typically recover an approved revenue requirement through embedded (average) cost-based rates, meaning rates designed to recover the costs of the existing system (and approved new investments) broadly across customers using class cost-of-service methods and allocators, rather than pricing each customer at the marginal cost of serving the next unit of load. By contrast, incremental (marginal) cost-based rates attempt to align charges more closely with the incremental costs caused by a particular customer or load addition. In practice, most retail electric rates are set based on embedded (average) costs such that, even though customers' bills vary with usage, the underlying per-kWh and per-kW charges are generally based on the revenue requirement to recover the costs of existing as well as new facilities rather than to reflect marginal cost (which can be much higher when equipment costs are high) of the new equipment. Because revenue requirements are translated into prices through class cost allocation and rate design, the impact of load growth on other customers depends on how incremental costs and incremental revenues are assigned across classes and recovered through the resulting rate structures.[xxi]

Regulatory commissions and utilities are increasingly developing targeted tariff and contractual provisions to reduce the risk that other customers bear the costs of serving new large loads. These provisions generally fall into three categories.

- Commitment and assurance mechanisms (such as long-term service commitments, contract demand requirements, milestone-based development obligations, upfront deposits, and/or other collateral) are used to improve confidence that forecasted load will materialize and persist long enough to support cost recovery.
- Minimum contribution mechanisms (such as minimum bills or minimum demand charges) ensure baseline contributions to fixed cost recovery even if realized usage is lower than anticipated.
- Exit and true-up mechanisms (such as early termination charges, exit fees, or refund limitations where utilities initially fund certain facilities) are intended to limit cost shifts if a project delays, downsizes, or departs before costs are recovered.[xxii]

Many jurisdictions are actively modifying retail tariffs and service rules for large loads, typically to clarify cost responsibility, reduce under-realization risk, and provide assurance that the costs and benefits of new infrastructure investment will be fairly distributed. As of late March 2026, over 75 large-load tariffs and service rules were in place or under consideration nationwide, though some allow for large loads to opt in rather than mandating minimum requirements for all qualifying customers.[xxiii]

However, concerns around large load cost responsibility persist, and cost allocation mechanics can still shift costs across customer classes. In ERCOT, for example, transmission cost recovery is allocated to retail load-serving entities based on each entity's share of demand during ERCOT's four highest system peak intervals, and ERCOT materials note that this system creates strong incentives for large commercial and industrial customers to avoid transmission costs in ways that are not equally available to residential customers. As a result, even if transmission investment per MWh declines on a system-average basis, the status quo cost allocation methodology can shift a larger share of costs toward entities with less ability to manage coincident-peak contributions.[xxiv]

Similar allocation concerns arise in other regions where transmission cost recovery is based on coincident peak or pro rata network load metrics. For example, Berkeley Lab notes that regions use a range of coincident-peak-based approaches, which can produce different class impacts depending on how load shapes align with peak conditions.[xxv] In New England, state representatives have raised distinct cost allocation concerns, noting that certain categories of transmission projects (including "asset condition" projects) are effectively allocated broadly to consumers on a pro rata basis across regional network load even where state stakeholders have limited visibility into project selection and review.[xxvi]

Open questions and reliability implications

Even where recent history suggests that load growth can exert downward pressure on average prices in some contexts, the magnitude and direction of future impacts will depend on system conditions and on project-level realization dynamics that remain uncertain. Beyond uncertainty around cost of service and project realization, the utility industry is studying three ways that large loads could drive additional costs: reliability risks, increased wear-and-tear due to high utilization, and increased challenges in scheduling and carrying out maintenance and repairs on a HLF grid.

Reliability-oriented guidance has emphasized that large load additions can create risks that are not well captured by standard "average load" metrics. In recent work on emerging large loads, reliability authorities have highlighted issues including the need for improved modeling and verification of grid interactions, as concerns remain that large loads could cause or exacerbate reliability issues that may drive need for additional system investment.[xxvii]

A related set of open questions concerns how sustained HLF load-driven high utilization interacts with the physical constraints and maintenance needs of grid assets. Sustained loading can tighten thermal limits on equipment and may accelerate aging mechanisms in components such as transformers, cables, and conductors, which could in turn affect replacement cycles and capital spending requirements. Moreover, it is unclear how increased utilization might constrain the ability to perform grid maintenance and repairs, given potential reductions to asset downtime. However, there is limited empirical evidence that translates these equipment-level effects into robust estimates of system-wide cost or rate impacts for emerging large-load growth. For purposes of this memo, these considerations are best treated as plausible technical drivers that merit attention in planning and interconnection processes, rather than as quantified system-wide impacts.[2]

Given these uncertainties, reliability guidance increasingly emphasizes early and ongoing coordination among large-load customers, utilities, and system operators. Practical expectations include timely sharing of load characteristics and operational plans; staged energization and ramp schedules aligned with system capability; and, where feasible, the ability to provide operational flexibility or curtailment under defined conditions.[xxviii]

Conclusion

The case that HLF loads can yield net system benefits and reduce rates is strongest in regions with demonstrable headroom on both the delivery system and in the generation fleet, such that incremental load can be accommodated with limited incremental investment. It is also the case at times when the cost of new equipment is at or below historical costs. It is also strongest where projects are supported by long-term commitments and rate structures that reduce stranded-cost risk and align revenues with cost responsibility, and where any incremental transmission investments required to serve the load strengthen the bulk grid and facilitate investment in generation resources with comparatively low $/MWh costs.

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Endnotes

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