Title

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Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities 2026 Update

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Electricity demand from large-load customers such as data centers is projected to grow significantly in the near term. While these large loads play an important role in advancing technology innovation and economic growth in the United States, meeting their energy needs requires utilities and regulators to consider important operational and financial risks, such as insufficient energy supply or underutilized investments, that can impact all customers. This paper builds on similar research published in January 2025, providing an overview of how utilities and regulators are managing these risks through different tariffs, including rate structures and electric service agreements. Regulators, utilities, customers, and other stakeholders can use this paper as a foundation when discussing issues and sharing perspectives on developing or reviewing large-load tariffs.

Introduction

U.S. electricity demand is projected to grow significantly in the next decade, largely driven by data center expansion and artificial intelligence applications, as well as growth in domestic manufacturing and electrification in other sectors (NERC 2026). Reliable energy supply and robust infrastructure are critical to the successful deployment and expansion of large loads such as data centers. Data centers are among the most energy-intensive building types due to their continuous operation, computing equipment, and cooling needs.[1] Lawrence Berkeley National Laboratory estimates that total U.S. data center electricity demand more than doubled (2.3x) from 2018 to 2024 and could triple (3.3x) from 2024 to 2028 (Smith et al. 2026).

Regulators, utilities, and large-load customers are developing tariffs including rate structures, electric service agreements (ESA), and special contracts designed to deliver reliable and affordable power, mitigate financial risks to ratepayers, and support energy and infrastructure deployment. Utility tariffs define the price, terms, and conditions of electricity service to end-use customer classes—such as residential, commercial, and industrial—and require approval by state or local regulators.[2]

This paper presents a series of tariff design elements that specifically seek to mitigate utility financial, planning, and operational risks, as well as support broader power system goals and objectives. They are

[1] There are several types of data centers that differ primarily in terms of application (e.g., cloud data centers supporting data and applications used by cloud service providers), size (e.g., a large technology company or cloud service provider supporting large-scale computing), and ownership (e.g., enterprise data centers that are typically owned and operated by individual companies versus colocation data centers that lease space).
[2] Tariffs that involve the transmission and sale of electricity in interstate commerce require approval from the Federal Energy Regulatory Commission.

organized to provide utilities, regulators, customers, and other stakeholders with an understanding of common design elements and how prevalent they are in practice. Within each element, we also present a series of examples from proposed and approved tariffs to illustrate how variable the implementation of each element is across the U.S., and where possible, we provide the logic provided for the design element selection.

Typology of Tariff Design Elements

We analyzed a sample of 55 tariffs derived from Halcyon's Large Load Tariff Tracker as of March 2026 and supplemented through independent research to identify key large-load tariff design elements (Appendix 1).[3] We identified how common and established the elements are and organized this paper based on a combination of the two factors.

To assess how commonly a large-load tariff design element had been implemented, we derived the share of tariffs, regardless of time period, that include each element and then assigned it to one of three categories (Table 1).

Table 1. Categories identifying commonness of tariff elements

Category	Percent of Tariffs Analyzed That Include Element
Very Common	>66%
Moderately Common	33%–66%
Less Common	<33%

To assess whether the elements are emerging or were established in older large-load-focused tariffs, we compared the share of tariffs containing each element among the tariffs proposed since January 2025 versus before January 2025 and then assigned each element to one of three categories (Table 2).

Table 2. Categories identifying adoption of tariff elements

Category	Description
Increasing Adoption	Higher after January 2025 than before January 2025 (i.e., increased more than 10 percentage points)
No Material Change in Adoption	Roughly equal after January 2025 and before January 2025 (i.e., changed less than ±10 percentage points)
Decreasing Adoption	Lower after January 2025 than before January 2025 (i.e., decreased more than 10 percentage points)

[3] The sample of 55 tariffs includes electric utility tariffs, contracts, and other frameworks. We developed the tariff sample primarily from Halcyon's large-load tariff tracker. We excluded entries that were not broadly available large-load rates, including most special contracts, transmission service agreements, line extension policies, and other non-rate provisions, while retaining special contracts that appeared intended for repeatable use with future customers. We also consolidated duplicate tariffs for utilities operating across multiple states, removed superseded tariff versions, and excluded secondary tariffs that were not the utility's primary large-load offering. We supplemented the Halcyon database with additional large-load tariffs and frameworks that were not included in the tracker through April 2026. The examples provided in this section also include additional riders and frameworks that are not part of the large-load tariff sample. These were included because they are either available to large-load customers or contain provisions applicable to large loads and therefore provide relevant context.

We then combined these elements to assign the type of practice associated with each element (Table 3).

Table 3. Type of practice of tariff elements

	Increasing Adoption	No Change in Adoption	Declining Adoption
Very Common	Established practice		Declining practice
Moderately Common	Emerging practice	Stable practice	
Less Common			

Each of the elements is organized into the categories (Table 4).

Table 4. Tariff elements by type of practice

Established Practice	Stable Practice	Emerging Practice	Declining Practice
Minimum demand threshold	Load factor threshold	Study requirements	Customer type
Minimum contract duration	Aggregation rules	Load ramp period	
Monthly demand charge	Load forecast requirement	Hold harmless	
Minimum billing demand	Price premium	Resizing or reassigning of contracted capacity	
Minimum bill		Exit fee	
Collateral requirements			
Direct assignment of costs			
Customer-specific resource procurement			

The frequency, commonness, and change in adoption of each tariff element is summarized in Appendix 2.

Established Practices

Minimum Demand Threshold

Nearly every large-load tariff includes a minimum demand (i.e., megawatts [MW]) threshold that customers must meet to be eligible for electricity service under the tariff. These requirements may apply at individual sites or on an aggregated basis across multiple sites (see Aggregation Rules). While the tariffs do not specify the rationale for the load thresholds, the thresholds may reflect the level at which a large load would trigger transmission upgrades necessary to ensure reliable interconnection to the system. In some jurisdictions, legislation requires utilities to establish these thresholds. While thresholds vary widely, ranging from 0.3 MW to 150 MW, the majority (75%) of the tariffs fall between 5 and 100 MW, with a median of 25 MW. No significant change has been observed in the demand thresholds since 2025.

Examples include:

- NorthWestern Energy's proposed Large New Load Tariff has a 5 MW minimum load requirement.
- Portland General Electric's proposed Schedule 96 has a 20 MW minimum load requirement. This threshold was driven by Oregon's House Bill 3546.
- AEP Ohio's Schedule DCT (Data Center Tariff) has a 25 MW minimum load requirement.

- Evergy Missouri's Large Load Power Service has a 75 MW minimum load requirement.
- Georgia Power's Time-of-Use – Supplier Choice schedule (TOU-SC-15) has a 100 MW minimum load requirement.
- Louisville Gas and Electric Company and Kentucky Utilities Company's (LG&E/KU) Extremely High Load Factor Rate (Rate EHLF) has a 50 megavolt-ampere (MVA) minimum load requirement. This is an isolated example of the threshold being defined with MVA as opposed to MW.

Minimum Contract Duration

Nearly every large-load tariff specifies a minimum contract duration (e.g., years) for customers taking service. Longer contract duration is used to mitigate the risks associated with serving large loads, including cost recovery uncertainty and potential stranded investment. In some cases, contract duration may be determined on a customer-specific basis and formalized through an ESA. Where standardized minimum term lengths are specified within the tariff, they range from 1 to 20 years. Since 2025, tariffs have generally trended toward longer minimum contract durations, with the median increasing from 5 years for tariffs proposed before 2025 to 12 years for tariffs proposed since 2025. The duration may include the load ramp period in some instances (see Load Ramp Period).

Examples include:

- Entergy Louisiana's Large Power, High Load Factor Power Service Rate has a minimum contract period of five years.
- Appalachian Power's Large Capacity Power Service has a minimum contract term of 12 years.
- Dominion's Schedule GS-5 has a minimum contract period of 14 years.
- El Paso Electric's proposed High Load Factor Power Service (Rate No. 50) has a minimum contract term of 20 years.

Monthly Demand Charge

Monthly demand charges (i.e., $/MW-month) are a core component of large-load tariffs and are based on a customer's peak demand during the billing period. They are used to recover capacity-related costs associated with the infrastructure needed to serve peak load. Demand charges are very common across large-load tariffs, and they are increasingly adopted in recent tariffs. They are typically implemented with different demand-based components, either unbundled by system function (e.g., generation, transmission, distribution) or combined into a single charge; the charges may also vary by time period (e.g., on-peak, off-peak) and by service voltage level.

Examples include:

- AEP Ohio's Data Center Tariff includes a distribution demand charge that varies based on the service voltage level (secondary or primary).
- Kentucky Power's Industrial General Service includes demand charges differentiated by both time-of-use period (monthly on-peak and off-peak billing demand) and service voltage level (secondary, primary, sub-transmission, and transmission). The tariff also specifies minimum demand charges by voltage level.

- Rappahannock Electric Cooperative's Schedule LP-DF (Large Power – Dedicated Facilities) monthly demand charge includes (i) a service charge based on installed MVA, adjusted to reflect the number of customers served by each substation and (ii) a delivery service charge based on installed MVA.
- Florida Power & Light's (FPL) Large Load Contract Service monthly demand charges include (i) a base demand charge, and (ii) an Incremental Generation Charge. The latter recovers the incremental costs incurred to serve the customer, based on the customer's applicable share of generation capacity and transmission interconnection revenue requirements.

Minimum Billing Demand

Large-load tariffs often include a minimum billing demand provision (i.e., $/month based on customer's contracted MW), which establishes a floor on the demand used for billing purposes regardless of actual usage.[4] This mechanism is used to ensure a baseline level of revenue recovery and to mitigate the risk of underutilization. This is very common and has seen an increase in adoption in recent large-load tariffs. Minimum billing demands are typically defined as a percentage of the customer's contract demand, with a median of 80% across the tariffs reviewed. No significant change has been observed in the percentage levels since 2025.

Examples include:

- Evergy Missouri's Large Load Power Service specifies a minimum billing demand equal to 80% of the annual contracted capacity.
- Salt River Project's E-67 rate specifies a minimum billing demand of 80% of the customer's forecasted demand, though the utility retains the option to reduce it based on the extent to which the customer pays for any generation resources and infrastructure that the utility would not otherwise procure or develop.
- Indiana Michigan Power's proposed Large Power Tariff specifies the minimum billing demand shall not be less than 90% of the greater of (i) the customer's contract capacity or (ii) the customer's highest previously established monthly billing demand during the past 11 months.
- Colorado Springs Utilities' Industrial Service – Large Load tariff specifies that during the initial 10-year contract period, the minimum billing demand will be 100% of the contracted demand for the calendar year. After the initial 10-year contract term, the minimum billing demand will be 68% of the maximum demand occurring during the last 12 months.
- Dominion Energy's Schedule GS-5 specifies a multicomponent minimum billing demand that includes: (i) a minimum distribution charge of 85% contracted demand, (ii) a minimum transmission charge of 85% contracted demand, and (iii) a minimum generation charge of 60% contracted demand.

[4] While some tariffs allow customers to exceed their contracted capacity under certain conditions (e.g., Ameren's LLPS permits a customer to temporarily exceed its contracted capacity with prior authorization and verification that the exceedance will not create reliability impacts), many other tariffs include provisions to discourage capacity exceedance. These provisions may require customers to increase their contracted capacity, specify that the utility does not guarantee service above the contracted capacity, or impose penalties such as exceedance charges or service suspension.

Minimum Bill

Many large-load tariffs include a provision that requires customers to pay a minimum monthly bill (i.e., $/month) regardless of actual energy consumption. This provision generally summarizes all minimum charge provisions in the rate schedule. It is commonly used in conjunction with minimum billing demand requirements to serve as a safeguard for cost recovery, ensuring that utilities recover a baseline level of revenue even if customer usage is lower than expected. Minimum bills are very common and are increasingly featured in new tariffs. The minimum bill typically incorporates multiple components, such as demand charges, customer charges, and volumetric energy charges including rate riders.

Examples include:

- Appalachian Power's Large Capacity Power Service sets the minimum monthly bill equal to the sum of (i) the customer charge, (ii) the product of the demand charge and the monthly billing demand, (iii) the product of the base billing energy and the monthly base energy charge, and (iv) all applicable adjustments.
- AEP Ohio's Schedule DCT sets the minimum monthly charge equal to the sum of (i) the customer charge, (ii) the product of the distribution demand charge and the monthly distribution billing demand, and (iii) the product of volumetric energy and all regulator-approved riders.
- El Paso Electric's proposed Large Load Power Service (Rate No. 51) establishes the minimum monthly charge as the sum of the (i) customer charge, (ii) the product of the demand charge and the monthly billing determinant, (iii) other non-consumption based applicable riders, (iv) tax adjustment, and (v) any applicable facility charges.

Collateral Requirements

Large-load tariffs often include collateral requirements to ensure that utilities are protected against non-payment and potential stranded cost risks. These provisions are very common and continue to be adopted in recent tariffs. Where required, collateral is typically calculated as a multiple of minimum monthly charges. In some instances, the collateral is assessed on a dollar-per-MW-of-contracted-capacity basis. Acceptable forms of collateral commonly include letters of credit, parental guarantees, or cash, and many tariffs incorporate mechanisms to reduce collateral based on creditworthiness (e.g., the minimum threshold to be eligible for reduced collateral requirements is typically is A- from S&P and A3 from Moody's) and/or liquidity of the company. Some tariffs include a mechanism that reduces collateral over time based on timely payments.

Examples include:

- Dominion's Schedule GS-5 requires collateral equal to $1.5 million per MW of contracted capacity, providing a capacity-based proxy for potential system exposure.
- FPL's Large Load Contract Service requires customers to post collateral equivalent to the total Incremental Generation Charge over the full contract term, directly tying collateral requirements to the estimated cost of new generation capacity needed to serve the customer.
- Colorado Springs Utilities' Industrial Service – Large Load requires collateral equal to the highest 36 months' equivalent of the minimum monthly bill during the full contract term.

- AEP Ohio’s Schedule DCT requires a collateral equal to 50% of total minimum charges over the contract term, but the required amount is reduced annually by one year's worth of minimum charges for each year the customer makes on-time payments, effectively allowing the customer to step down collateral over time as performance risk declines.
- NorthWestern Energy's proposed Large New Load Tariff requires collateral that is at least equal to the exit fee, which must be no less than three years of minimum demand billing and minimum energy billing applicable to the terminated or reduced service commitment. This establishes a floor while preserving the utility's ability to require higher amounts in the ESA. The required collateral amount may be adjusted over time based on compliance with minimum billing obligations and creditworthiness requirements.

Direct Assignment of Costs

Large-load customers may be directly assigned the costs of serving them, including the incremental cost of new network infrastructure investments needed to provide service or the cost of new resource adequacy requirements (such as capacity procured on their behalf). Direct assignment provisions can serve different purposes depending on how they are designed, but their central function is cost containment: ensuring that existing customer classes are not subsidizing the infrastructure and resource costs driven by new large loads.

Direct assignment may apply at different stages of service and to different cost categories. During the development or load ramp period, direct assignment is often used to recover customer-specific, transitional costs needed to hold, reserve, or procure capacity before the customer reaches full operations. For cost recovery during this period, utilities often rely on a Contribution in Aid of Construction (CIAC), an upfront payment made by a customer to fund utility infrastructure investments. CIACs have historically been used for distribution infrastructure expenses in excess of what is normally covered by a utility's line extension policy,[5] but they are receiving greater consideration for other applications, such as covering the cost of new transmission network upgrades needed to interconnect large loads.[6,7] After the customer reaches its full contracted demand level, direct assignment can be used to recover the long-term costs of dedicated infrastructure, customer-specific resources, or incremental system investments required to serve the customer's ongoing load.

Examples include:

- Silicon Valley Power directly assigns all costs of designing and building the substation required to serve each large commercial customer through the company’s Load Development Fee.

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[5] For example, under AEP Ohio’s line extension policy, non-residential customers are responsible for 40% of the total cost of the line extension plus the incremental costs of premium services. Payments for premium services and for costs exceeding standard thresholds are considered CIAC. Customers who paid a CIAC may be entitled to a refund if a new customer utilizes all or part of the facilities within 50 months of completion. Ohio Power Company, P.U.C.O. No. 22, Terms and Conditions of Service, Sheet No. 103-6 to 103-8 (Apr. 8, 2026).

[6] CIACs are typically used to offset the utility’s rate base, reducing the total costs that customers will have to pay. The magnitude of the infrastructure costs may make upfront contributions difficult for smaller customers with restricted access to capital or credit.

[7] Another option for direct assignment is to use a cost-tracking vehicle to isolate, track, and recover costs from each customer. This vehicle can either be a unique customer class for each customer or location, or a customer-specific charge, such as an energy charge based on a customer-specific power purchasing agreement.

- The Pennsylvania Public Utility Commission in April 2026 published a final order on a large-load tariff template. The order recommended that load-serving entities in the state assess CIACs for new customers that recover all interconnection costs, including network transmission upgrade costs that would otherwise not have been constructed.
- Pacific Gas and Electric's (PG&E) Electric Rule 30 establishes a framework for transmission-level interconnection (50–230 kilovolts) requiring large-load customers to make upfront advances for service facilities, interconnection upgrades, and network upgrades, with refunds issued up to 10 years through PG&E's Base Annual Revenue Calculation formula. Customers who terminate service before the refund period ends forfeit any remaining refunds in an effort to protect existing ratepayers from stranded cost risk.
- NorthWestern Energy's reservation capacity charge in its proposed Large New Load Tariff allows the utility to recover the costs of securing supply. The charge may reflect the cost of holding existing portfolio capacity, advancing generation development, or securing power supply through contractual arrangements.
- Evergy Missouri's Large Load Power Service tariff directly assigns interim capacity costs to customers when the customer's load cannot be served using the utility's existing system capabilities. In that circumstance, Evergy may procure the necessary capacity, with the customer subject to the full cost of that capacity through an additional "Interim Capacity Adjustment" demand charge.
- Under Minnesota Power's proposed special contract to serve a Google data center, Google is responsible for early development costs associated with new generation and related infrastructure, as well as for transmission network upgrades needed to interconnect and serve the facility.

Elements Enabling Customer-Specific Resource Procurement

Large-load customers may have specific energy goals that are not typically addressed in industrial tariffs. For example, data center customers may require a higher level of reliability than a standard customer, or desire resource-specific energy procurement to meet corporate goals. To accommodate these preferences, large-load tariffs may include provisions that enable customized service configurations. Below, we provide examples utilities accommodating customer-specific preferences for behind-the-meter (BTM) generation, customer-led resource procurement such as power purchase agreements (PPAs) and bring-your-own capacity (BYOC) arrangements, and load flexibility.

Behind-the-Meter Resources

Some large-load tariffs allow or require customers to install on-site generation resources such as natural gas turbines, solar, or batteries to serve some or all of their electricity demand, reduce their contracted capacity with the utility, or provide flexibility during grid emergencies.[8]

Examples include:

- AEP Ohio's Schedule DCT allows data center customers to interconnect BTM resources designed to operate in parallel with AEP Ohio's system. Customers may elect to use BTM resources to offset

[8] This practice draws on concepts traditionally found in standby rates. Which establish terms for customers that rely on both self-generation and utility service.

their contract capacity, but they must install and maintain equipment capable of instantaneously curtailing load equal to or greater than the BTM generation output. Otherwise, AEP Ohio reserves the right to suspend service.

- Evergy Missouri's Large Load Power Service offers an optional Demand Response & Local Generation Rider that compensates customers for using on-site generation or load flexibility to reduce consumption during peak and constrained grid conditions. Customers receive bill credits based on measured curtailment performance.
- Cheyenne Light, Fuel and Power (CLFP)'s Large Power Contract Service tariff requires large-load customers to obtain certain resources to satisfy their capacity requirements. These may include on-site back-up generators as well as other types of on-site or off-site resources and contracts.

Customer-Led Resource Procurement

Customer-led resource procurement includes utility-managed PPAs for specific resources and BYOC options. Under utility-managed PPAs, customers may select specific generation or storage resources to support their power supply needs. Customers then pay either the full cost of those resources or the incremental cost relative to a baseline alternative. BYOC arrangements allow customers to procure their own generation resources to support their energy needs, and customer-owned capacity counts toward the utility's resource adequacy requirements.

Examples include:

- NV Energy allows eligible large customers to select specific energy resources to meet their sustainability goals. Customers pay the full cost of procuring the selected resource through an ESA. NV Energy holds the PPA with the resource developer and is responsible for procuring and delivering the energy to the customer.
- Ameren Missouri allows large-load customers to request that specific energy resources including renewables, demand-side management, energy efficiency, or battery storage be deployed in place of or in addition to the utility's preferred resource portfolio (determined through integrated resource planning). The requesting customer is responsible for covering all costs associated with the selected resources, including capital costs and expenses, as specified in a negotiated energy choice agreement. Ameren Missouri owns and operates the resources and retains discretion over the modified resource plan that incorporates the energy resources to ensure safe and reliable service.
- While not a tariff, DTE Electric's special contract with Green Chile Ventures (a subsidiary of Oracle Corporation) allows the customer to request energy storage capacity from DTE to support its data center load and resource adequacy needs. The customer bears all costs associated with the energy storage portfolio over a 15-year recovery period for each project. DTE Electric owns the storage assets (or enters into tolling agreements with third parties) and operates them in the Midcontinent Independent System Operator (MISO) wholesale market. In exchange for bearing all costs, the customer receives 100% of incremental MISO capacity, energy, and ancillary services market revenues—net of charging costs—as credits on their monthly invoice.

Load Flexibility

Load flexibility provisions allow or require large-load customers to reduce, shift, or otherwise modify their electricity consumption during specified system conditions. These provisions may take the form of demand response programs, interruptible rates, mandatory curtailment during grid emergencies, or utility access to on-site generation. These provisions are designed to help utilities manage reliability, accelerate load interconnection, and/or, in some cases, defer or avoid incremental infrastructure costs. Each utility approach differs. Some large-load tariffs explicitly compensate customers for providing load flexibility, while others prohibit new large-load customers from participating in flexibility programs on the basis that they may counteract the financial incentives created by minimum demand provisions.

Examples include:

- Under Evergy's Large Load Power Service, customers are eligible for the Demand Response & Local Generation Rider, which compensates customers for verified load reductions achieved through load flexibility or on-site generation. Under the rider, Evergy can curtail participating customers' demand during peak hours for either reliability or economic reasons. Customers may select either the constrained or unconstrained service options, with the former including certain periods when the utility cannot curtail service. Both options compensate the customer with demand-based bill credits that vary by month, with the unconstrained option offering larger credits.
- Idaho Power's Flex Peak Program provides a demand response option for large-load customers. The program compensates participating customers for reducing load during summer weekday peak periods. Customers may participate through manual or automatic interruptions and can receive both capacity payments and volumetric energy payments, subject to minimum reduction requirements and limits on event timing, duration, and total annual event hours.
- Colorado Springs Utilities' Interruptible Service Rate is available for customers taking service under the Electric Large Load. Under the interruptible rate, the customer agrees to be completely interrupted for up to 100 hours per year, with the potential for additional interruption hours beyond the initial 100 hours by customer agreement. In return, the customer receives energy and demand-based credits, but there is no non-performance penalty.
- East Kentucky Power Cooperative's Data Center Power Tariff is compatible with the company's Rate D - Interruptible Service. The interruptible rate options include a monthly per-kW credit based on the annual hours of interruption, where the credit increases as annual hours increase, with certain seasonal and hourly limitations to the interruption periods. The cooperative charges a 5x penalty of the firm demand charge for non-performance.
- FPL's Large Load Contract Service explicitly prohibits customers from being eligible for service under Load Control Riders. FPL did not provide justification for the provision.

Stable Practices

Load Factor Threshold

Utility tariffs may specify a load factor (i.e., ratio of average load to peak load over a defined time period, e.g., monthly, seasonally, or annually) that a customer taking service under the tariff must maintain, typically expressed as a minimum threshold. Among tariffs that include this requirement, minimum load factor thresholds range from 60% to 85%, and the underlying rationale for these requirements varies.

Examples include:

- Dominion's Schedule GS-5 eligibility includes a 75% minimum load factor requirement. The utility indicates that this is intended to differentiate large customers with above-average load factors and enable more transparent and targeted rate design.
- Entergy Louisiana's Large Load, High Load Factor Power Rate Schedule has an 80% minimum average monthly load factor requirement; no rationale was provided.
- FPL's Large Load Contract Service rate has an 85% minimum load factor requirement, which the utility indicates is a necessary threshold for achieving downward rate pressure and system benefits.
- LG&E/KU's Extremely High Load Factor Service (Rate EHLF) includes an 85% minimum average monthly load factor requirement, informed by the utility's research of large data center performance.
- Arizona Public Service's Extra High Load Factor tariff includes a 92% minimum load factor requirement, for a minimum of nine months of the prior 12-month period. However, the utility is proposing changes to that tariff, including removing the minimum load factor requirement.
- NorthWestern Energy's proposed Large New Load Tariff includes a customer-specific minimum load factor that is specified in the ESA. The utility indicates the requirement is to ensure that the generation capacity costs, which are embedded in the volumetric energy charge, are sufficiently recovered.

Aggregation Rules

Some tariffs include provisions governing whether and how customer load may be aggregated for eligibility purposes. This may help mitigate potential risks associated with large-load customers attempting to qualify for the smaller rate schedules by splitting their load into smaller sites. Where aggregation is allowed, the applicable minimum load threshold typically remains unchanged; however, some tariffs establish separate thresholds for individual sites and for aggregated loads.

Examples include:

- AEP Ohio's Schedule DCT applies to customers expected to exceed 25 MW at a single location or have an aggregated total contract capacity exceeding 25 MW within the utility's service territory.
- Appalachian Power's Large Capacity Power Service establishes a 100 MW minimum threshold for a single site and a 150 MW threshold for aggregated sites.
- Consumers Energy's Rate GPD (Large General Service Primary Demand) applies to customers with at least 100 MW of load, either at a single site or aggregated across multiple sites under common ownership, provided that each site has a minimum load of 20 MW.
- NV Energy includes differentiated aggregation rules based on customer type. Government entities may aggregate facilities that are under a common budget and control, while non-government customers may aggregate load with Public Utilities Commission of Nevada approval, provided each facility being aggregated has a load of at least 1 MW.
- Public Service Company of Oklahoma's proposed Large Power and Light Tariff applies to customers expected to exceed 10 MW at an individual site or on an aggregated basis.

Load Forecast Requirement

In addition to traditional utility load forecasts, new forecasting approaches have been developed by utilities to improve long-term planning for large-load customers (ESIG 2025). In some cases, large-load tariffs may require customers to provide additional, forward-looking details that support such efforts. These requirements are intended to improve visibility into the timing, scale, and ramp-up of customers, which can materially affect both energy growth and peak demand. Specific load forecasting provisions in customer tariffs are seeing no material change in adoption in recent tariffs. The provisions may require customers to submit periodic forecasts, to provide updates on deviations from such forecasts, and to adhere to agreed-upon reporting standards. In at least one case, utilities may include enforcement mechanisms for non-compliance or inaccuracies, but this is not common.

Examples include:

- NorthWestern Energy's proposed Large New Load Tariff requires customers to provide load forecasts and timely updates of deviations from them, with specified standards set in the ESA. Failure to comply may constitute violation of the customer's service agreement and may be subject to enforcement remedies.
- Xcel Colorado's proposed Transmission Large Service schedule requires customers to provide a five-year load forecast of expected monthly on-peak and off-peak demand and energy, along with at least semi-annual updates. Inaccuracies do not constitute a breach of the ESA, but customers are expected to prepare the load forecasts in good faith and to notify the utility of material changes.

Price Premium

Utilities may include pricing mechanisms that require customers to pay at least the incremental cost of service (the cost of generation, transmission, distribution, or a combination of these cost categories). These provisions may recover customer-specific costs, require payments for incremental system investments, or require additional contributions that benefit existing customers, such as through energy assistance programs. Exact implementation varies by utility depending on regulatory requirements or customer needs but commonly includes customer-specific charges or riders. Their common objective is to ensure that, at a minimum, new large-load customers do not create upward rate pressure for existing customers, and, where possible, provide incremental benefits to other customer classes.

Examples include:

- Evergy Missouri's Large Load Power Service includes demand charges set at a level to sufficiently recover the embedded cost of service as well as an incremental amount. The incremental amount is based on the time-value of money of accelerated generation resource investments relative to when the utility would otherwise have needed such resources.
- PPL Electric, as part of a settlement, will assign $11 million of Universal Service Rider[9] costs to a newly created large customer class. As a result, the new class will partially subsidize the costs associated with the utility's residential low-income program.

[9] The Universal Service Rider (USR) charge is applied to each kilowatt-hour supplied to customers, who take distribution service under applicable tariffs. The USR charge provides for recovery of the costs associated with universal service programs provided by the Company to residential customers.

- Minnesota Power's proposed special contract to provide service to a Google data center includes a $1 million annual contribution from Google for five years to support the utility's affordability and energy efficiency programs.

Emerging Practices

Study Requirements

Utilities require prospective customers to undergo system impact and feasibility studies to assess the infrastructure, interconnection, and upgrade requirements needed to serve the new load. These studies support prudent system planning and help identify the scope, timing, and cost of necessary utility grid upgrades and are often performed as part of the load interconnection process. The explicit inclusion of these study requirements in large-load tariffs is moderately common and increasing among recent tariffs. Utilities typically require prospective customers to pay the costs associated with conducting these studies.

Examples include:

- NorthWestern Energy's proposed Large New Load Tariff requires prospective customers to execute a Development Agreement and provide a Development Deposit to fund system studies evaluating feasibility, timing, cost, and system impacts. The utility may draw upon and require replenishment of the deposit as needed, with any unused portion refunded to the customer.
- East Kentucky Power Cooperative's Data Center Power tariff requires prospective customers to submit a detailed application and pay a non-refundable application fee (scaled by load size) to initiate a utility-led load study. The study process evaluates interconnection requirements, costs, and system impacts, including coordination with PJM Interconnection for transmission-level analysis, with study costs effectively recovered through the application fee.
- Evergy Missouri, through their rules and regulations, requires customers with loads greater than 25 MW to fund system evaluation and planning studies through a series of refundable deposits. Deposits must be replenished to cover total study costs, with unused amounts refunded. Customers are placed in a study queue based on the timing of submitted information and deposits.

Load Ramp Period

Some tariffs provide large-load customers with a maximum number of months to reach their contracted load levels. Such maximum allowable load ramp periods are moderately common and are seeing increasing adoption in recent large-load tariffs. In some cases, the load ramp period is determined on a customer-specific basis. Load ramp periods may either be embedded within the minimum contract duration or be treated as a separate provision. Where specified, load ramp periods generally range from four to five years.

Examples include:

- El Paso Electric's proposed High Load Factor Power Service Rate (Rate No. 50) includes a load ramp period of up to four years, embedded within the minimum contract term.
- Dominion's Schedule GS-5 includes a maximum load ramp period of four years, with a minimum annual ramp requirement of 20% of contracted capacity, embedded within the minimum contract term.

- Appalachian Power's Large Capacity Power Service includes a maximum load ramp period of five years, separate from the minimum contract term.

Hold Harmless

Hold harmless provisions and mechanisms are designed to ensure that existing customers do not experience rate increases when new large-load customers are connected to the system. These provisions typically require the utility to demonstrate that the revenue collected from a large-load customer is sufficient to cover the costs incurred to serve that customer. If there is a shortfall, the large-load customer may be responsible for making up the difference. Implementations vary: some utilities conduct a ratepayer impact analysis for each customer prior to service, others perform periodic incremental cost tests comparing revenue to cost, and some include formulaic backstops that automatically adjust customer charges to prevent cost-shifting. Increasingly, regulators require utilities to empirically demonstrate that existing customers are not harmed by new large customers.

Examples include:

- Xcel Colorado's proposed incremental cost test under Schedule Transmission Large (TL) service compares revenue from large-load customers against the incremental costs of the transmission and generation resources used to serve them. The test evaluates transmission and generation separately, meaning that over-collection in one category cannot offset under-collection in the other. In the case of under-collection, Xcel would increase the corresponding Schedule TL charge and credit the resulting surcharge revenue to other customer classes.
- NV Energy includes a hold-harmless backstop that is incorporated into the ESA pricing model through an Annual Capacity Protection Cost. The mechanism ensures that the customer's all-in effective rate is not lower than the otherwise applicable rate. This is intended to ensure that under the energy arrangement the customer continues to contribute to embedded system costs at least at the level that would have been recovered under the standard bundled rate.
- Portland General Electric's Peak Growth Modifier (PGM), approved by the Oregon Public Utility Commission, splits the utility's revenue requirement into pre-growth and growth-related assets. The growth-related fixed generation and transmission investments are allocated to the customer classes responsible for incremental system peak demand, rather than the total system peak demand. Transmission investments are growth-related when triggered by new or increasing load, and generation investments are growth-related when triggered by incremental capacity or energy needed to reliably serve increased demand. PGM allocations are also indefinite rather than tied to a fixed allocation period, meaning growth-related revenue requirements are allocated using the PGM, unless evidence later shows that the asset should be combined with the rest of the rate base (e.g., if the asset no longer supports the customer class responsible for the growth).

Resizing or Reassignment of Contracted Capacity

Utility tariffs may define the terms and conditions for customers to resize their contracted capacity for purchase from the utility or to reassign or sell some of their unused contracted capacity obligations to another utility customer. This element is moderately common and is usually discussed in the tariff in the context of the exit fee. In some cases, utilities commit to making reasonable efforts to mitigate a departing customer's exit obligation, such as by re-marketing the released capacity or by finding replacement customers.

Examples include:

- AEP Ohio's Schedule DCT allows customers to assign up to 25% of contract capacity to another data center customer in lieu of paying some or all of the exit fee.
- Indiana Michigan Power allows large-load customers to reduce up to 20% of their contracted capacity after first five years with 60 months written notice without having an exit fee; reductions or terminations beyond 20% require 60 months of advance notice and payment of an exit fee.
- Ameren Missouri will use commercially reasonable efforts to mitigate the amount of the exit fee by selling wholesale capacity in the market up to the minimum demand, or by finding a replacement customer.

Exit Fee

Large-load tariffs often include an exit fee (e.g., dollar amount) for customers that terminate service prior to the end of the contract term. These provisions are another mechanism used to mitigate the financial risk of premature customer departure. Exit fees are an increasingly common feature in recent tariffs, and a typical approach is to charge the customer the equivalent of the minimum monthly charge for a certain period of time.

Examples include:

- Evergy Missouri's Large Load Power Service tariff includes an exit fee that is equal to the minimum monthly bill multiplied by the greater of the remaining contract term or one year. A minimum of 36 months' notice is required. If less notice is provided, an additional exit fee applies, equal to two times the minimum monthly bill for each month below the 36 months' notice requirement.
- AEP Ohio's Schedule DCT includes an exit fee equal to 36 months of minimum charges. A customer may only terminate their service after completion of the fifth year of contract after the load ramp period. The customer may assign up to 25% of contract capacity to another Schedule DCT customer in lieu of paying some or all of the exit fees.
- Kentucky Power's Industrial General Service includes an exit fee equal to five years of minimum billing. The customer may only terminate after the first five years of the initial contract term and must give at least five years' notice.
- NV Energy includes an exit fee equal to the total value of the remaining incremental cost of the contracted asset, calculated as the estimated kWh consumption the customer would have used over the remaining contract term multiplied by the difference between the contract rate ($/kWh) and the levelized cost estimates for NV Energy's most recent commission-approved renewable facilities ($/kWh).
- Ameren Missouri's Large Load Customer Service includes an exit fee equal to the minimum monthly bill multiplied by the lesser of the remaining contract term or five years (plus any remaining term of the load ramp period). A minimum of 24 months' notice is required. If less notice is provided, an

additional exit fee applies. That fee equals two times the minimum monthly bill for each month below the 24 months' notice requirement.

Declining Practices

Customer Type

Utilities can specify the large-load customer type that must take service under a tariff (e.g., data centers and cryptocurrency mining operations). Customer type-based eligibility is often avoided to maintain non-discriminatory rate design, but it can also be driven by legislation.

Examples include:

- AEP Ohio's Schedule DCT is only for customers that operate a data center.
- Entergy Arkansas' Large Power High Load Density Service is only for customers who are hosting or directly engaged in cryptocurrency mining operations.
- Portland General Electric's proposed Schedule 96 is only for customers who are engaged in data center services. This specification was driven by Oregon's House Bill 3546, which requires a separate and distinct classification of service for data centers from other commercial or industrial customers.
- East Kentucky Power Cooperative's Data Center Power Tariff is only for centralized facilities that are used primarily or exclusively for electronic information services (e.g., data centers and cryptocurrency mining).

Appendix 1: Tariffs, Frameworks, and Rules Included in Analysis

Utility	Tariff/Framework/Rule	PUC Case Number	Regulatory Status (as of Aug 6, 2026)
Large-Load Tariffs			
AEP Ohio	Schedule DCT	24-0508-EL-ATA	Approved
Ameren Missouri	Large Load Customer Service	ET-2025-0184	Approved
Appalachian Power	Large Capacity Power Service	24-0854-E-42T	Approved
Appalachian Power	Schedule L.P.S. (Large Power Service)	PUR-2025-00057	Approved
Arizona Public Service	Extra High Load Factor	E-01345A-25-0105	Pending approval
Black Hills Power	Economic Flexible Load Service (EFLS)	EL25-019	Approved
Chelan County PUD	Schedule 4	N/A	Approved
Cheyenne Light Fuel and Power (CLFP)	Large Power Contract Service	20003-233-ET-24	Approved
Cleco Power	Large Power Service	U-36923	Approved
Colorado Springs Utilities	Industrial Service – Large Load (ELL)	N/A (2026 Rate Case Filing)	Approved
Consumers Energy	Large General Service Primary Demand Rate GPD	U-21859	Approved
Delmarva Power	General Service – Large Demand (GS-LD)	25-0826	Pending approval
Dominion	Schedule GS-5	PUR-2025-00058	Approved
DTE Electric	Special Contract with Green Chile Ventures LLC	U-21990	Approved
Duke Energy Carolinas	Schedule HLF (High Load Factor)	E-7 Sub 1329	Pending approval
Duke Energy Florida	Large Load Customer Rate Schedule (LLC-1)	20260064	Pending approval
Duke Energy Kentucky	Rate DT	2024-00354	Approved
East Kentucky Power Cooperative	Data Center Power Tariff	2025-00140	Approved
El Paso Electric	Schedule 33A (Large Economic Development Rate)	56903	Approved
El Paso Electric	High Load Factor Power Service Rate (Rate No. 50)	26-0000062	Pending approval
El Paso Electric	Large Load Power Service Rate (Rate No. 51)	26-0000062	Pending approval
Entergy Arkansas	Large Power High Load Density Service	23-070-TF	Approved

Entergy Arkansas	Special Rate Customer Contract	25-055-P	Approved
Entergy Louisiana	Large Load, High Load Factor Power Service Rate	U-36959	Approved
Evergy Missouri	Large Load Power Service	EO-2025-0154	Approved
Florida Power and Light	Large Load Contract Service	20250011	Approved
Georgia Power	Time of Use – Supplier Choice (TOU-SC-15)	44280	Approved
Idaho Power	Schedule 19 (Large Power Service) and Schedule 33 (Special Contract with Brisbie)	IPC-E-25-16	Approved
Indiana Michigan Power	Industrial Power Tariff	46097	Approved
Indiana Michigan Power	Large Power Tariff	U-21986	Pending approval
Kentucky Power	Industrial General Service	2024-00305	Approved
LG&E/KU	Extremely High Load Factor Service	2025-00113	Approved
Mecklenburg Electric Cooperative	Schedule LPS-U (Large Power Service)	PUR-2025-00160	Interim implementation
Minnesota Power	Google Electric Service Agreement	E015/M-26-159	Pending approval
Montana-Dakota Utilities	High Density Contracted Demand Response Rate 45	PU-22-194	Approved
New York Municipal Power Agency	Rider A – Rates and Charges for High Density Load Service	18-E-0126	Approved
Northern Indiana Public Service Company	Data Center Customer #1 Special Contract	46322	Approved
NorthWestern Energy	Large New Load Tariff	2026.04.023	Pending approval
NV Energy	Clean Transition Tariff	24-05022	Approved
Otter Tail Power Company	Super Large General Service	20-719	Approved
PacifiCorp	Large-Load Service Contract between PacifiCorp and a Large-Load Customer	26-035-05	Approved
PacifiCorp	Schedule 401	UE 463	Pending approval
Portland General Electric	Schedule 96	UM 2377	Approved
PPL Electric	Rate Schedule LP-6	R-2025-3057164	Approved

Public Service Company of Oklahoma	Large Power and Light Tariff	2025-000075	Pending approval
Rappahannock Electric Cooperative	Schedule LP-DF	PUR-2025-00048	Approved
Salt River Project	E-67	E-00000A-25-0069	Approved
Shenandoah Valley Electric Cooperative	Schedule LPD-2	PUR-2025-00190	Interim implementation
Southwestern Electric Power Company	Electric Service – Large Load (ES-LL)	58796	Pending approval
Wisconsin Electric Power Company (We Energies)	Very Large Customer (VLC) and Bespoke Resources Tariff	6630-TE-113	Approved
Wisconsin Power & Light (WPL)	Individual Contract Rate Agreement	6680-TE-115	Approved
Xcel Energy Colorado	Large General Service – Transmission	26AL-0137E	Pending approval
Xcel Energy Minnesota	Large General Time of Day Service	25-289	Approved
Frameworks and Rules			
Commonwealth Edison	Revisions to General Terms & Conditions (GT&C) for Large Loads	25-0677	Approved
Pacific Gas and Electric	Electric Rule 30	A2411007	Interim implementation

Appendix 2: Summary of Tariff Element Frequency, Commonness and Change in Adoption

Tariff Element	Frequency	Commonness	Change in Adoption
Minimum Demand Threshold	51	●●●	—
Aggregation Rules	20	●●○	—
Load Factor Threshold	13	●○○	—
Customer Type	9	●○○	▼
Minimum Contract Duration	47	●●●	—
Load Ramp Period	23	●●○	▲
Exit Fee	31	●●○	▲
Collateral Requirements	43	●●●	—
Study Requirements	33	●●○	▲
Minimum Bill	47	●●●	▲
Minimum Billing Demand	39	●●●	▲
Monthly Demand Charge	46	●●●	▲
Price Premium	6	●○○	—
Load Forecast Requirement	12	●○○	—
Explicit Load Forecast	10	●○○	—
Requires Forecast Update Cadence	11	●○○	—
Direct Assignment of Costs	45	●●●	—
For Capacity Reservation	4	●○○	▲
For Interconnection Upgrades	38	●●●	▲
For Generation/Capacity Costs	28	●●○	▲
For Network Transmission Upgrades	10	●○○	▲
Hold Harmless	25	●●○	▲
Formulaic Backstop	11	●○○	▲
Incremental or Marginal Cost	19	●●○	—
No Harm Analysis	13	●○○	▲
Customer-Specific Resource Procurement	43	●●●	▲
Behind-the-Meter Generation	28	●●○	▲
Customer-Led Resource Procurement	25	●●○	▲
Load Flexibility	27	●●○	—
Resizing or Reassigning of Contracted Capacity	26	●●○	▲

Note: The number of reviewed tariffs ranges from 53 to 55 by element, as PG&E Rule 30 and ComEd's Revisions to GT&C are included only where relevant.

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