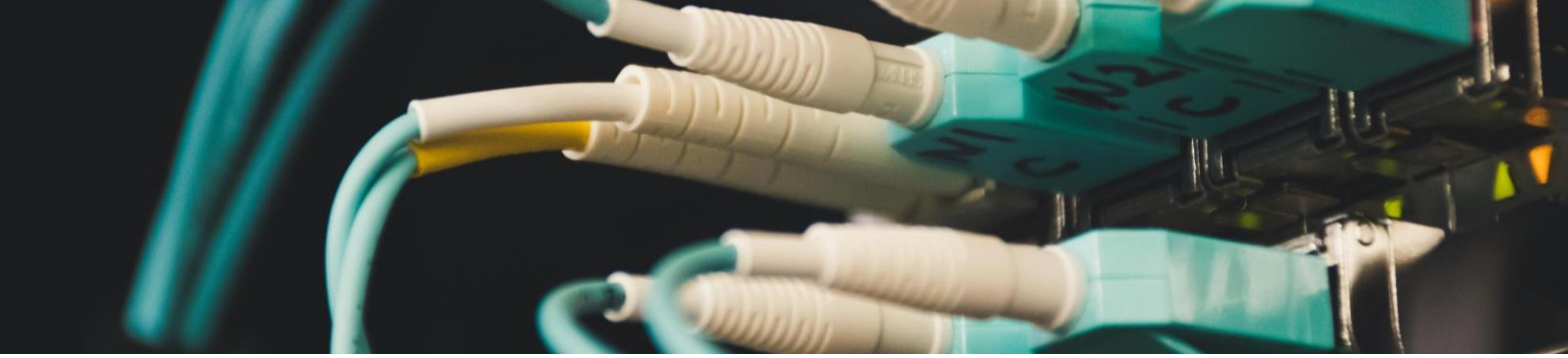

Leveraging Large Load Flexibility to Facilitate Access to Power While Protecting Customers

Considerations for State Regulators

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CONTENTS

EXECUTIVE SUMMARY

Rapid electricity demand growth from data centers and other large loads threatens grid reliability and affordability. Utilities typically build generation and grid capacity to serve all loads at all times, spreading costs across all customers. This approach is too slow and expensive to meet the pace of demand.

Large load flexibility offers a solution. Large loads that commit to curtail consumption when directed—backed by energy storage, on-site generation, or operational curtailment capabilities—can interconnect faster and at lower cost. To take advantage of this opportunity, this policy brief recommends that states define *flexible large load* as a class and then implement that definition across four policy domains: (1) the load interconnection process, (2) ratemaking, (3) load forecasting and planning, and (4) bring-your-own-capacity (BYOC) policies.

Define a Flexible Large Load Class

As a threshold step, state regulators should establish a formal definition of *flexible large load*. The definition should be based on a set of enforceable curtailment commitments meeting specific technical requirements. The commitments that undergird the definition should:

- **Be voluntary**, not mandated. A voluntary framework lets the market determine the right mix of flexible and inflexible loads, avoids disrupting projects already in queue, and recognizes that not all data centers can economically invest in flexibility.
- **Be made in the interconnection process** (or as a condition of retail service), so that the commitment informs study assumptions and infrastructure planning.
- **Be long-term** to support long-term planning. Temporary commitments have value as a bridge to full service, but only long-term commitments should qualify a load for queue priority, differential rate treatment, and incorporation into long-term planning.
- **Guarantee minimum curtailment** performance across four parameters:
    - **Depth:** Minimum percentage of contract capacity curtailed (e.g., 50%+)
    - **Speed:** Response time to operator signal (e.g., 5–10 minutes)
    - **Duration:** Minimum hours per curtailment event (e.g., 4 hours)
    - **Availability:** Minimum hours available per year (e.g., 2%+ of annual hours)

Load Interconnection Rules that Enable Flexibility

Even if the Federal Energy Regulatory Commission (FERC) asserts jurisdiction over transmission-level load interconnections, states will retain substantial authority. State regulators can use this authority in two ways:

1. **Prioritize study of flexible loads.** In queue-based or cluster study processes, advance the interconnection requests of loads that make long-term, binding flexibility commitments ahead of those that do not. Speed-to-power is the single strongest incentive for participation.

2. **Require utilities to incorporate flexibility commitments into study assumptions.** Today, utilities typically model large loads at non-coincident peak demand under worst-case conditions, ignoring any curtailment capability. When a customer commits to curtail on operator signal, that commitment should be modeled in the interconnection study. Doing so can dramatically reduce the network upgrades identified, and therefore the cost and timeline to interconnect.

Rates that Reflect the Lower Cost Causation and Risk Profile of Flexible Large Loads

States have authority over retail and distribution service rates as well as the allocation of FERC-jurisdictional costs among retail customer classes. Those authorities can be used to:

- **To the extent possible, directly assign network upgrade costs via contributions in aid of construction (CIAC) or other upfront payment requirements.** Direct cost assignment protects other customer classes and provides the right price signal: flexible loads that avoid upgrades pay less, while inflexible loads bear the costs they cause. Where multiple loads share upgrade needs, the triggering load can pay upfront and be refunded as others connect.
- **Adjust demand charges to reflect flexibility.** If network upgrade costs are directly assigned, distribution and transmission demand charges would ideally recover only embedded system costs and need not differ between flexible and inflexible loads. But if upgrades are socialized, flexible loads should pay lower demand charges than inflexible ones. Depending on the regulatory structure of the state, capacity demand charges could be reduced to reflect the capacity value of flexibility commitment.
- **Calibrate minimum demand charges, exit fees, and collateral requirements.** States and utilities have sought to prevent cost-shifting by requiring new large loads to commit to stringent minimum demand charges, exit fees, and collateral requirements. Where underlying demand charges already reflect the lower cost causation and risk profile of flexible large loads, these protective provisions can apply uniformly. Where they do not, regulators should reduce them for flexible large loads to reflect their lower stranded-asset risk.
- **Require time-variant energy pricing for all large loads.** Market-based or time-of-use energy rates incentivize flexible operations on the margin, with flexible large loads best positioned to respond to real-time price signals.

Incorporate Flexibility into Load Forecasting and Planning

Traditional load forecasting methods are inadequate for large, concentrated loads that lack historical precedent. States should:

- **Improve base forecasting for large loads** by requiring better data from interconnection customers, disaggregating large loads from the general forecast, and evaluating multiple scenarios. Recent guidance from the Energy Systems Integration

Group (ESIG) identifies five key metrics: project realization rate, energization date, load realization, load ramping, and load factor/shape.

- **Embed flexibility commitments in planning models.** ESIG recommends a six-step approach: (1) characterize loads in detail, (2) improve forecasts, (3) quantify capacity needs absent flexibility, (4) quantify potential capacity contributions of flexibility, (5) calculate avoided infrastructure investment, and (6) develop a regulatory framework to secure those benefits. States that adopt this approach can quantify and capture the avoided costs that flexibility provides.

Ensure Bring-Your-Own-Capacity Frameworks Accommodate Flexibility

States are exploring requirements that large loads bring-your-own-capacity. BYOC rules should avoid inadvertently penalizing flexible large loads:

- **Exempt qualifying flexible large loads from BYOC requirements, or count curtailment capability as eligible capacity.** A load that commits to curtail reliably achieves the same purpose as one that procures new generation—avoiding or reducing the need for capacity buildout. Failing to recognize this dilutes the commercial incentive to invest in flexibility.
- **Allow temporary flexibility commitments to satisfy near-term BYOC obligations** where the BYOC requirement is driven by a temporary supply constraint.
- **Anchor BYOC enforcement in retail service authority.** State utility regulators have authority over retail service, which provides the most durable enforcement mechanism, regardless of how federal jurisdiction over interconnection evolves.

States need not wait for FERC. Whether or not FERC asserts jurisdiction over large load interconnection to the transmission system, states retain critical authority over distribution-level interconnections, retail service terms, rate design, resource planning, and load forecasting. By acting now to define a flexible large load class and implement reforms across the four policy domains of (1) the load interconnection process, (2) ratemaking, (3) load forecasting and planning, and (4) bring-your-own-capacity (BYOC) policies, state regulators can accelerate load interconnection, protect existing customers, and attract economic development.

WHAT IS LOAD FLEXIBILITY AND WHY DOES IT MATTER?

Rapid load growth poses a challenge for the electricity grid and those who govern it. Both legacy infrastructure and governance frameworks are ill-suited to meet load growth reliably at the pace and scale expected while protecting customers from adverse impacts. Central to this challenge is the fact that utilities generally build out generation and grid capacity to serve all loads at all hours and spread the costs to provide such infrastructure across the total pool of customers. As many states are now seeing, this type of buildout is both slow and expensive, requiring extensive generation, transmission, and distribution capacity expansion to serve data centers reliably at times of peak system stress. If load interconnections outstrip supply additions, reliability and affordability will suffer. But if data center interconnections must wait for completion of grid infrastructure, many will choose not to proceed, squandering vital economic opportunities, undermining global economic competitiveness, and risking American national security.

One solution to this problem—that both accelerates interconnection and can lower rates for consumers—is to prioritize large loads that commit to operate flexibly, curtailing their draws from the grid when directed by transmission operators and balancing authorities under tight operating conditions. With a regulatory framework to support them, large load flexibility commitments can avoid the need for infrastructure buildout and thereby lower rates while speeding load interconnection.[1]

Large loads can deliver on flexibility commitments by moderating their energy consumption and by meeting electricity needs through nearby resources that provide power without relying on the transmission system. Data centers—which comprise the largest share of expected growth in large loads, and which are typically conceived of as inflexible loads—can modulate compute-related consumption by scaling down computing power for tasks that are less performance-sensitive (including some AI training tasks), postponing tasks that are less time-sensitive, or shifting tasks that are less location-sensitive to other sites.[2] Data centers may also be able to reduce consumption in certain circumstances by modulating cooling system consumption.

Large loads also have several options to meet power needs while reducing or eliminating reliance on available grid supply or delivery capacity. These include co-locating energy supply resources like utility-scale generation, storage, or smaller behind-the-meter distributed energy resources with loads behind a single point of interconnection; integrating load and supply within single-campus "energy parks;"[3] and integrating energy supply resources electrically adjacent to (but not behind the meter of) loads to provide joint value

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[1] *See* Tyler H. Norris et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, Nicholas Institute for Energy, Environment & Sustainability 2 (2025), https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (*Rethinking Load Growth*) (finding that the existing grid could support an additional 76 GW of new load if that load could be curtailed for 0.25% of its maximum uptime); Carlo Brancucci et al., *Flexible Data Centers: A Faster, More Affordable Path to Power*, Camus Energy, encoord, & Princeton University Zero Lab (Dec. 2025), https://cdn.prod.website-files.com/60dbdcca2e4b1919e8894fa5/6930abf1be0f36db6fc27157_Whitepaper%20-%20With%20Appendix.pdf (*Flexible Data Centers*); Martin Ross & Jackson Ewing, *Data Centers and Generation Capacity over the Next Decade: Potential Benefits of Flexibility*, Nicholas Institute for Energy, Environment & Sustainability 7–10 (2026), https://nicholasinstitute.duke.edu/publications/data-centers-and-generation-capacity-over-next-decade (*Data Centers and Generation Capacity*).

[2] *See* Williams et al. Power-Flexible AI Factories: A UK-First Demonstration of Grid-Responsive AI Infrastructure. Emerald AI, EPRI, National Grid, Nebius, March 2026.

[3] *See generally* Eric Gimon et al., *Energy Parks: A New Strategy to Meet Rising Electricity Demand*, Energy Innovation (Dec. 2024), https://energyinnovation.org/wp-content/uploads/Energy-Parks-Report.pdf.

(reducing net resource adequacy and transmission impacts), but otherwise operating independently during normal conditions.[4]

A growing body of work has documented the significant benefits that large load flexibility commitments can provide.[5] Less attention has been paid, however, to the regulatory framework needed to deliver on the theoretical potential that flexibility commitments promise. This policy brief on state-level reforms to promote flexibility, like the previous brief on federal flexibility reforms,[6] attempts to help fill that gap.

STATE ROLE IN ENABLING LOAD FLEXIBILITY

States have a central role in enabling large load flexibility. While the U.S. Department of Energy (DOE) recently proposed that FERC assert jurisdiction over the interconnection of large loads to the transmission system,[7] states will retain an important role in the regulation of large load customer connections whether or not FERC carries out that proposal. This section briefly describes the Federal Power Act's (FPA's) jurisdictional split between federal and state authority over large load interconnections. It summarizes DOE's recent proposal and explains how states will retain a role regardless of how FERC proceeds.

Jurisdictional Basics under the Federal Power Act

The FPA vests FERC with jurisdiction over "the transmission of electric energy in interstate commerce" and "over all facilities for such transmission or sale of electric energy."[8] FERC's jurisdiction extends to "all rates and charges made, demanded, or received by any public

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[4] *See* Andrew Levitt et al., *Proposed Options for Bilateral Integration of Generation Portfolios and Load (BIGPAL)* (Oct. 14, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251014/20251014-item-03b---eolian-brattle-proposed-options.pdf. Backup generators could also provide a measure of load reduction capability but have lesser ability to facilitate load flexibility commitments because they are designed for limited emergencies rather than regular longer-term use. *See* Miles Farmer et al., *How DOE's Proposed Large Load Interconnection Process Could Unlock the Benefits of Load Flexibility*, Nicholas Institute for Energy, Environment & Sustainability 4–5 (Nov. 2025), https://nicholasinstitute.duke.edu/publications/how-does-proposed-large-load-interconnection-process-could-unlock-benefits (Nicholas Federal Load Flexibility Report).

[5] *See* Tyler H. Norris et al., *Rethinking Load Growth* at 2; Carlo Brancucci et al., *Flexible Data Centers*; Martin Ross & Jackson Ewing, *Data Centers and Generation Capacity*; Chris Cox et al., *Bringing Data Center Flexibility into Resource Adequacy Planning: A Case Study of NV Energy*, GridLab (Sept. 2025), https://gridlab.org/portfolio-item/data-center-flexibility-nv-energy-case-study-report/; EPRI, *Powering Data Centers: U.S. Energy System and Emissions Impacts of Growing Loads*, 2024 White Paper (Oct. 2024), https://www.epri.com/research/products/000000003002031198; Thomas W. Kirchstetter et al., *DOE Data Center Load Flexibility Workshop Summary*, Lawrence Berkeley National Laboratory (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-03/final_doe_data_center_load_flexibility_workshop_summary.v0307.pdf.

[6] Miles Farmer et al., Nicholas Federal Load Flexibility Report.

[7] *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking, FERC Docket No. RM26-4-000 (Oct. 23, 2025) (DOE ANOPR).

[8] 16 U.S.C. § 824(b).

utility for or in connection with" interstate transmission or wholesale sales, along with "all rules and regulations affecting or pertaining to such rates or charges."[9] But the FPA reserves to the States authority "over facilities used in local distribution," and over retail sales of electricity.[10]

As retail regulators, states have traditionally regulated service to large load customers. State laws define who has access to retail service and who is permitted to sell energy to end-use consumers, and on what terms. States oversee Electricity Service Agreements signed by large load customers with their load-serving entities or tariffs that set the terms of retail service for such customers.[11] States have also traditionally overseen processes through which utilities manage the interconnection process for retail customers. Increasingly, however, as retail loads have become larger, many are connecting directly to the transmission system rather than to the distribution system. State-supervised interconnection processes generally have not distinguished between distribution-system and transmission-system interconnections.

The division between federal authority over transmission and state authority over distribution has not been sharply defined. The FPA does not define transmission facility or distribution facility. In 1996, FERC issued Order No. 888, which mandated open access on the transmission system. To determine which facilities would be subject to FERC's jurisdiction and which would remain under state jurisdiction, FERC developed a seven-factor test for identifying distribution facilities.[12] That test is aimed at identifying the

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[9] *Id.*

[10] *Id.*

[11] *See, e.g.*, Xcel Energy, *Petition: Contracts for Provision of Electric Service to a New Large Customer's Minnesota Data Center Project*, Minnesota Public Utilities Commission Docket No. E002/M-22-572, Attach. A: Electricity Service Agreement (filed Oct. 31, 2022); Indiana Util. Reg. Comm'n, *Order on Verified Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement, Renewable Energy Purchase Agreement, and Tranche Agreements with Blocke, LLC Arising from Operation of Facilities in Jeffersonville, Indiana and for Establishment of Confidential Procedures*, Indiana Utility Regulatory Commission Cause No. 45975 (Apr. 24, 2024); *see also* Andrew Satchwell et al., *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities*, Lawrence Berkeley National Laboratory 2 (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-01/electricity_rate_designs_for_large_loads_evolving_practices_and_opportunities_final.pdf.

[12] The seven factors identified in Order No. 888 for distinguishing between distribution and transmission facilities are: (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems; it rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported on to some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) local distribution systems will be of reduced voltage. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg 21,540, at 402 (May 10, 1996) (cross-referenced at 75 FERC ¶ 61,080).

primary function of a facility as a basis for determining jurisdiction.[13] In practice, the seven-factor test is fact-dependent[14] and often lacks clarity as to jurisdiction over particular facilities.[15]

As the wholesale regulator, FERC oversees the tariffs maintained by Regional Transmission Organizations/Independent System Operators (RTOs/ISOs). FERC thus regulates regional capacity markets and regional resource adequacy constructs, where they exist, and oversees regional transmission planning and cost allocation, and unbundled transmission rates. FERC also oversees the interconnection process for large generators. FERC's role in these matters means that state policy objectives—such as to support development of large loads, limit the costs of serving large loads from impacting other customers, or to mitigate reliability and affordability impacts of rapid load growth—will often require corresponding reforms to tariffs, policies, or practices that are under federal jurisdiction. For example, while state regulators may directly regulate the terms of retail contracts for large loads, certain components of the cost of infrastructure to serve large loads will originate from FERC-jurisdictional rates and necessarily flow into retail bills,[16] such as regional capacity charges or the costs of regional transmission facilities.

Both FERC and states play critical roles in regulating the supply of energy: with state authority over the resource mix, generation siting, and broader economic and environmental regulation, and FERC authority over the large generator interconnection process and wholesale power rates. Likewise, the authority to shed load is subject to both federal and state legal obligations. RTO/ISOs, for example, possess authority to direct the shedding of load-serving entity demand consistent with FERC-jurisdictional tariffs or operating agreements and North American Reliability Corporation (NERC) requirements,[17]

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[13] *See California Pac. Elec. Co., LLC*, 133 FERC ¶ 61,018, at P 45 (2010).

[14] *See, e.g., S. California Edison Co*., 153 FERC ¶ 61,384, at P 19 (2015) ("The seven factor test is not subject to formulaic application or categorical standards. Rather, the test requires comprehensive consideration of how the totality of the circumstances bears on each of the seven factors.").

[15] The seven-factor test's ambiguity is evidenced by the many cases in which its boundaries have been tested. *See, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 181 FERC ¶ 61,056 (2022), *order on reh'g*, 182 FERC ¶ 61,095 (2023); *Sw. Power Pool, Inc.*, 180 FERC ¶ 61,192 (2022); *DTE Electric Company v. Midcontinent Independent System Operator, Inc*., 180 FERC ¶ 61,222 (2022); *S. California Edison Co.,* 153 FERC ¶ 61,384; *ISO New England Inc*., 178 FERC ¶ 61,115, *order on reh'g*, 179 FERC ¶ 61,186 (2022), *aff'd sub nom. Green Development, LLC v. Federal Energy Regulatory Commission*, 77 F.4th 997 (D.C. Cir. 2023); *Consumers Energy Co. v. Midcontinent Independent System Operator, Inc*., 171 FERC ¶ 61,020, *order on reh'g*, 172 FERC ¶ 61,201 (2020); *Sw. Power Pool, Inc*., 149 FERC ¶ 61,051 (2014); *City of Pella, Iowa v. Midwest Independent Transmission System Operator, Inc*., 134 FERC ¶ 61,081 (2011).

[16] *See Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988).

[17] NERC reliability standards are subject to FERC oversight pursuant to FPA section 215.

while transmission owners and load-serving entities must comply with both federal and state retail requirements in effectuating any such directives.[18]

Ultimately, states seeking to achieve particular policy goals with respect to large loads must assess their policy tools to ensure that each is effective without the support of corresponding federal action, or that the complementary federal action necessary to achieve a policy goal can be readily secured.

Even if FERC Asserts Jurisdiction over Large Load Interconnection, States Retain Key Authorities over Large Loads

In October 2025, DOE proposed that FERC assert jurisdiction over the interconnection of large loads (the DOE "Advanced Notice of Proposed Rulemaking" or the "DOE proposal"). FERC has not yet acted on the DOE proposal, but has gathered public comment on the potential action. If finalized in substantially the same form as DOE proposed,[19] the rule would preempt state authority over certain large load interconnections. Ultimately, FERC could elect to act on only a subset of the policy ideas set forth in the DOE proposal, or it could modify the scope of FERC's authority over large load interconnections.

Even under the DOE proposal, however, states would retain significant authority to regulate large loads. The DOE proposal would limit FERC jurisdiction to interconnection of new loads greater than 20 MWs to the transmission system. As such, state authority to regulate large load interconnections to the distribution system—which may constitute a significant amount of large load interconnections under FERC's seven-factor test[20]—and to regulate the interconnection of large loads below the adopted size threshold to the transmission system would remain.

The DOE proposal, if adopted, would constrain some of the state's currently available policy tools for regulating large loads. State regulation of the interconnection of loads above 20 MW to the transmission system would likely be preempted, either entirely or to the extent that such requirements conflict with federal obligations. Yet even under this scenario, there is a significant chance FERC would allow projects that are already advancing in state

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[18] *See, e.g.,* PJM, *Jurisdictional and Legal Principles relating to CIFP – Large Load Additions* 5 (Sept 15, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20250915/20250915-item-08---jurisdictional-and-legal-principles-relating-to-cifp--large-load-additions---pjm-presentation.pdf (explaining PJM's authority over wholesale load forecast and wholesale load shed); *see also* PJM, *Large Load Additions Pre-CIFP Education* 12–16 (Sept. 2, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20250902/20250902-item-03---large-load-additions-pre-cifp-education---pjm-presentation.pdf (describing PJM rules regarding shedding of firm load, including the role of the transmission owner in determining customer prioritization).

[19] FERC is not legally required to adopt DOE's proposal. Rather, under section 403 of the DOE Organization Act, FERC must "consider and take final action on any proposal made by the Secretary [of the DOE]," but need not necessarily adopt that proposal or a variant thereof. 42 U.S.C. § 7173(b). *See, e.g., Grid Reliability & Resilience Pricing; Grid Resilience in Reg'l Transmission Organizations & Indep. Sys. Operators*, 162 FERC ¶ 61,012, at P 14 (2018).

[20] Order No. 888, 75 FERC ¶ 61,080 at 402.

processes to continue in those state processes. Given the immense amount of load currently interconnecting via state processes,[21] states acting now have a significant opportunity to shape transmission system interconnection.

Perhaps most importantly, states will retain authority to regulate retail rates, including determining which entities are eligible to receive retail service and sell energy to end-use consumers. States also have authority over siting and permitting of facilities. Further, states will continue to have authority over the distribution system, including policies affecting load shed to retail customers. In short, regardless of the fate of the DOE proposal, states will continue to be critical in shaping the policy landscape for large loads.

ORGANIZING STATE POLICIES TO UNLOCK LOAD FLEXIBILITY

Recommendation: States Should Define a New Class of Flexible Large Loads

Effective policies to unlock the potential for large load flexibility all rely on the regulator's ability to differentiate readily between flexible large loads and standard (inflexible) large loads. Thus, an important starting point is for state regulators to establish a definition of what it means for a large load to be flexible. This policy brief recommends that states structure this definition around a set of enforceable flexibility commitments made by the large load. Once this definition and the flexibility commitments it rests upon are established, rules governing the defined class of flexible large loads could be employed across four policy domains: interconnection; ratemaking; planning; and BYOC rules. While one could envision gradations in the definition of flexible large loads (e.g., low, medium, and high levels of flexibility), for purposes of simplicity and administrative efficiency, this brief recommends a single definition that captures the minimum threshold set of commitments that a large load must make to be treated as a flexible large load under these four policy areas.

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[21] *See* John D. Wilson et al., *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*, Grid Strategies 3 (Nov. 2025), https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf (Grid Strategies Upward Revision Report) (finding 166 GW of peak load growth forecasted between 2025 and 2030); Catherine Boudreau, *ERCOT's Large Load Queue Has Nearly Quadrupled in a Single Year*, Latitude Media (Dec. 3, 2025), https://www.latitudemedia.com/news/ercots-large-load-queue-has-nearly-quadrupled-in-a-single-year/ (ERCOT "has about 226 GW of large load customers in its interconnection queue as of November."); Oncor, *Oncor Reports 2024 Results; Announces $36 Billion 2025–2029 Capital Plan*, https://www.oncor.com/content/dam/oncorwww/documents/investorrelations/financial-news/4Q-2024%20Oncor%20Earnings%20Release.pdf (Oncor's large commercial and industrial interconnection queue exceeded 137 GW as of the end of 2024).

States need not all use the same definition of flexible large load. In an emerging area of policy, it is beneficial for each state to consider this question independently and arrive at an approach that works in its own regulatory context. Nevertheless, this brief recommends four broad measures for any state. Specifically, as explained in greater depth below, the commitments necessary to qualify as a flexible large load should:

1. Be voluntary
2. Be made in the interconnection process and incorporated into the interconnection agreement or a separate concurrent agreement
3. Be long-term
4. Contain minimum commitments across four parameters:
    a. Depth of curtailment
    b. Speed of curtailment
    c. Minimum hours available per curtailment event
    d. Minimum hours available for curtailment per year

Load Flexibility Commitments Are Relevant to Four Related Policy Domains

This policy brief describes four areas of policy that states must adjust to unlock the benefits of load flexibility. These policies do not involve subsidies. Nor do they force flexibility commitments on large loads that lack the willingness or capability to undertake them voluntarily. Rather, what is needed is for states to implement policies that enable large loads to make proactive binding commitments to operate flexibly and to make those commitments in a way that allows the state's utilities to avoid unnecessary infrastructure costs.

The four policy areas addressed in this brief are:

1. ***Load interconnection rules***: State regulators have authority to define the procedures and terms upon which loads interconnect to the grid. As explained, even if FERC asserts jurisdiction over large load interconnections to the transmission system, substantial authority will remain with the states. The Interconnection section in this policy brief recommends that state regulators use this authority to (1) prioritize the study of flexible large loads and (2) ensure that binding flexibility commitments are incorporated into interconnection study assumptions so that those commitments can be relied upon to avoid unnecessary infrastructure investments.
2. ***Ratemaking:*** Many states have begun to require that utilities promulgate large load tariffs, and other rate terms specific to large loads. These large load tariffs, which are an important step in the right direction, should be adjusted to reflect the unique cost causation and risk profile of flexible large loads. Put simply, flexible large loads that avoid new infrastructure by virtue of their flexibility commitments should see rate terms that reflect those commitments. The Ratemaking section explains how these principles can be applied to the distribution, transmission, and generation charges for flexible large loads, including minimum demand charges, collateral provisions, and other typical large load tariff provisions.

3. ***Load forecasting and planning:*** To drive additional savings in the planning processes for transmission development and resource adequacy procurement, states should ensure that utility load forecasts incorporate the binding flexibility commitments made by flexible large loads. The Planning section explains the load forecasting processes and how flexibility commitments could be included.
4. ***BYOC Policies:*** Several states have begun to impose BYOC policies for new large loads. A later section explains this trend and how BYOC policies can be structured to accommodate large load flexibility commitments.

Flexibility as a Voluntary Commitment, Distinct from Emergency Curtailment Provisions

Given the important benefits of load flexibility, a state regulator might reasonably ask whether all large loads should be required to operate flexibly. There are two reasons why not. First, a huge volume of data center load has already been designed and proposed into existing queues; it would be unfair and unreasonable to require these projects to redesign and resubmit their interconnection requests mid-process. Second, even as a policy applied to new interconnection requests, it is unlikely to be economically efficient or even viable for all data centers—let alone all large loads—to make the hardware investments necessary to operate flexibly. There are important differences among data centers in terms of their size, location and functional requirements. A voluntary approach, in which large loads can decide whether to invest in flexibility based on policies that accurately value the benefits of flexibility to the grid, allows the market to determine the right balance and configuration of flexible and inflexible loads.

One state has implemented, and others are considering, policies that would shed data center loads before other loads in emergencies.[22] Such mandatory measures can help to maintain reliability and to ensure that data center loads are shed before residential loads. But if curtailment is confined to emergencies (as it must be to apply universally), then it is unlikely to function as a practical tool that can be relied on to avoid infrastructure investments. To avoid infrastructure investments, utilities and system planners will need to ensure that flexible large loads are available to curtail more frequently, during times when the grid is stressed or particular assets are nearing their operating limits—circumstances that may arise well before load shedding occurs or an emergency is declared.

In this regard, a large load that makes a flexibility commitment is distinct from an *interruptible load* as that term has traditionally been understood in FERC's definition of Network Integration Transmission Service.[23] In contrast to interruptible loads, for which service would be interrupted only in an emergency and grid operators would continue to plan the system in a manner designed to minimize or eliminate such interruptions, large

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[22] *See, e.g.*, An Act Relating to the Planning for, Interconnection and Operation of, and Costs Related to Providing Service for Certain Electrical Loads and to the Generation of Electric Power by a Water Supply or Sewer Service Corporation, 89th Tex. Leg., Senate Bill 6 (Texas SB 6).

[23] *See, e.g.*, FERC, *Pro Forma Open Access Transmission Tariff*, § 29.2.

load customers making flexibility commitments would expect to be curtailed by design. Such commitments would be backed by reliable processes and infrastructure, like energy storage facilities, or inherent characteristics of the load.[24]

Flexibility Commitments Arise Through the Process of Interconnecting or Obtaining Electric Service and are Finalized Prior to Taking Service

The definition of flexible large load advanced here centers on the load entering a binding commitment to operate flexibly. The timing of the commitment matters: it should be made up front, either as a condition of interconnection, as a condition of obtaining retail service, or both.[25] By requiring that the commitment be made through an up-front agreement upon which service is contingent, state regulators can ensure that the commitment is relevant to the assessment of what infrastructure (distribution, transmission, and capacity) is necessary to serve that customer. In addition, an up-front process allows the flexible large load customer to understand what costs it must bear (and what it can avoid) before it is required to deepen its financial commitment.

Qualifying Flexibility Commitments Are of Indefinite or Long-Term Duration

Qualification as a flexible large load should be contingent on binding commitments to operate flexibly for as long as the large load is taking retail service, or at least for the duration of the minimum agreement upon interconnection. We make this recommendation because long-term commitments are the only way to ensure that flexible operations are captured in long-term distribution, transmission, and resource adequacy planning. Because the avoidance of infrastructure needs is what insulates existing customers from affordability and reliability impacts, a long-term commitment should be required to give the customer interconnection preference, warrant differential rate treatment, or influence the utility or state's planning assumptions. Only a long-term flexibility commitment is relevant to all four policy domains discussed here.

States may also wish to explore the concept of a "temporary" flexibility commitment. A temporary flexibility commitment has value insofar as it allows large loads to connect prior

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[24] *See supra* the section describing load flexibility (describing ways that large customers may achieve flexibility sufficient to make a flexibility commitment); Antora, Post-Technical Conference Comments, FERC Docket No. AD24-11-000, at 2 (filed Dec. 11, 2024) (noting that "thermal batteries can provide 24/7 heat by charging only ~1/3 of the time" and thereby provide clients "the benefits of low-cost renewable power without requiring the factories themselves to curtail when renewable power is not available, prices rise and during periods of coincident peak transmission system use and demand.").

[25] In cases where FERC takes jurisdiction over the interconnection process, states could incorporate the commitment in a retail service agreement or as a tariff condition for taking retail service.

to the completion of network upgrades necessary for permanent service.[26] In addition, a temporary commitment is relevant to potential BYOC requirements. To the extent a state's BYOC requirement is driven by a temporary supply constraint, a temporary flexibility commitment could help to alleviate this constraint. Thus, states that are considering imposing BYOC requirements because of near-term supply constraints may wish to allow temporary commitments to qualify to meet those requirements.

Table 1. Comparison of Temporary and Long-Term Flexibility Commitments

	Temporary Flexibility Commitments	Long-Term Flexibility Commitments
Interconnection: queue prioritization	No prioritization	Prioritization
Interconnection: study assumptions	Temporary flexibility commitments are modeled	Permanent flexibility commitments are modeled
Rates	No separate rate treatment with regard to transmission and distribution-related charges; potential temporary reduction in capacity-related charges, depending on rate structure and resource adequacy regime	Separate rate treatment to reflect different cost causation and risk profile
Load forecasting and planning	No separate treatment in long-term load forecasting and planning	Flexibility commitments incorporated into load forecasting and planning
BYOC	Temporary flexibility commitments can justify reduction in BYOC requirement during the period of the commitments	Permanent flexibility commitments can reduce or eliminate BYOC obligation

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[26] For a temporary commitment to allow a customer to connect prior to network upgrade construction, the interconnecting utility must account for the commitment in its study process. As such, temporary commitments are relevant to the discussion later in this policy brief on how to account for flexibility commitments in study assumptions. But we recommend against allowing temporary commitments to qualify customers for queue priority (discussed later).

Qualifying Flexibility Commitments Should Guarantee Curtailment Across Key Parameters

State regulators should define the flexible large load class in terms of minimum curtailment commitments across four quantitative parameters. Flexible large loads may have reasons to exceed them (for example, to avoid incremental infrastructure), but these minimum requirements would determine eligibility to be treated as a flexible large load across the four policy domains:

- **Depth of curtailment:** To qualify, flexible large loads should commit to curtail a minimum percentage of their contract capacity when called upon. State regulators should consider this minimum percentage based on the record of the applicable proceeding, but there may be little reason to establish a new class for flexible large loads without demanding substantial curtailment capability, such as 50% of contract capacity or greater.
- **Responsiveness to operator signal:** Flexible large loads should be required to commit to curtail within a specified period of time from the signal of the interconnecting utility or system operator. There is no single right answer to this question currently; state regulators have multiple models to draw from and should consider working together to adopt a national standard. For example, NERC's reliability guidelines define operating reserves as curtailable in 10 minutes,[27] and a recent proposal from PJM Interconnection would make its new non-firm contract demand transmission service curtailable within 5 minutes.[28]
- **Duration of curtailment:** Flexible large loads should be required to sustain their curtailments for minimum time periods if called upon. For example, a four-hour curtailment commitment would likely be sufficient to address nearly all system peak and contingency events.[29]
- **Minimum hours available per year:** Flexible large loads should agree to curtail for a certain number of hours per year if called upon. For example, interruptible demand response programs might require a minimum available curtailment in the range of 2% of hours per year.[30] Studies, including those from Duke University's

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[27] NERC, *Reliability Guideline: Operating Reserve Management—Version 3 4*(Apr. 15, 2021), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/rs/reliability_guideline_template_operating_reserve_management_version_3.pdf.

[28] PJM, Initial Brief, Docket Nos. EL25-49-000 & 001, AD24-11-000, EL25-20-000, at 25 & Attach. A: Illustrative Language for New Tariff, Part XI, at 18 (filed Feb. 23, 2026).

[29] States could consider applying longer duration requirements during the pendency of acute and prolonged grid events, for example when the relevant entity has called and Energy Emergency Alert Level 2 or higher.

[30] For example, programs administered by PG&E and SCE limit annual interruption to a maximum 180 hours, just above 2% of annual hours. *See* PG&E, *Electric Schedule E-BIP: Base Interruptible Program*,

Nicholas Institute for Energy, Environment & Sustainability, show additional benefits at higher curtailment levels.[31] Based on the record of the applicable proceeding, state regulators may seek to balance those benefits against an assessment of the willingness and ability of flexible load to commit to higher levels of curtailment.

INTERCONNECTION

As discussed previously, states now oversee the interconnection process for all retail customers, including large loads. Even if FERC asserts jurisdiction over the interconnection of large load customers to the transmission system, states will retain jurisdiction over interconnections to the distribution system and potentially also over all interconnections below a certain size threshold. Moreover, under any FERC implementation of DOE's proposal, states are likely to retain jurisdiction over transmission-level interconnections for a transitional period until grid operators have implemented new rules, and will continue to have siting and permitting authority.

Generally, the interconnection process involves a study by the interconnecting utility that determines what infrastructure must be built to accommodate the generator or load customer's request.[32] Until recently, this process has received relatively little attention, because large customers could usually obtain prompt service.[33] However, as load interconnection requests have proliferated and transmission and distribution network

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Cal. P.U.C. Sheet No. 57988-E, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-BIP.pdf; SCE, *Schedule TOU-BIP: Time-Of-Use-General Service Base Interruptible Program*, Cal. P.U.C. Sheet No. 89060-E, https://www.sce.com/sites/default/files/custom-files/PDF_Files/ELECTRIC_SCHEDULES_TOU-BIP.pdf. Montana-Dakota Utilities Co., for its part, limits annual interruptions to 200 hours annually. Montana-Dakota Utilities Co., *State of South Dakota: Electric Rate Schedule – SDPUC Volume No. 3*, Section No. 3 Original Sheet No. 20, High Density Contracted Demand Response Rate 45, at 1, https://puc.sd.gov/commission/Tariffs/Electric/mdu/Section3/20.pdf.

[31] *See, e.g.,* Tyler H. Norris et al., *Rethinking Load Growth* at 20.

[32] Depending on the jurisdiction, the interconnection process may also involve an assessment by the relevant RTO. *See, e.g.,* ESIG, *Forecasting for Large Loads: Current Practices and Recommendations* 42–43 (Dec. 2025), https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Large-Loads-Forecasting-report-2025.pdf (*Forecasting for Large Loads*).

[33] *See, e.g.,* Ryan Quint et al., *An Assessment of Large Load Interconnection Risks in the Western Interconnection*, Western Electricity Coordinating Council 11 (Jan. 2025), https://www.wecc.org/sites/default/files/documents/products/2025/Report_WECC%20Large%20Loads%20Risk%20Assessment%204.pdf (*Assessment of Large Load Interconnection Risks*) (large data center requests are "putting a strain on load interconnection queues that have historically not been a major pain point for utilities."); *Why Power Interconnection Timelines Are Delaying Data Center Builds*, Datacenters.com (Feb. 22, 2026), https://www.datacenters.com/news/why-power-interconnection-timelines-are-delaying-data-center-builds ("Historically, interconnection followed a predictable path. Developers submitted load requests, utilities performed studies, upgrades were identified, and timelines were manageable.").

capacity have become more constrained, large customers increasingly encounter delays.[34] Study processes are more likely to yield results finding that network upgrades are required to accommodate new service requests.[35] In addition, grid operators are encountering generation resource supply constraints.[36] In non-RTO regions, those constraints may

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[34] Interviews by the authors with large load developers confirmed that they are encountering increasingly scarce system headroom and facing larger costs and longer delays to interconnect. *See also* Nathan Case, *Why Does it Take So Long to Connect a Data Center to the Grid*, Camus (July 1, 2025), https://www.camus.energy/blog/why-does-it-take-so-long-to-connect-a-data-center-to-the-grid ("our power system doesn't have enough extra transmission capacity and generation to serve dozens of gigawatts of new, high-utilization demand 100% of the time . . . and building new transmission infrastructure and generation requires years of permitting, land acquisition, supply chain management, and construction."). This mirrors dynamics in the generator interconnection context where, for example, the DOE has explained that "[t]he combination of limited transmission capacity, increased request volume, and interconnection complexities has led to uncertainties, delays, and higher costs . . . ." Will Gorman et al., *Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035*, US Department of Energy 1 (Apr. 2024),https://www.energy.gov/sites/default/files/2024-04/i2X%20Transmission%20Interconnection%20Roadmap.pdf (*Transmission Interconnection Roadmap*). As a result, large customers have begun to experience significant delays to interconnect to the grid. *See, e.g.*, Josh Saul, *Data Centers Face Seven-Year Wait for Dominion Power Hookups*, Bloomberg (Aug. 29, 2024), https://www.bloomberg.com/news/articles/2024-08-29/data-centers-face-seven-year-wait-for-power-hookups-in-virginia?sref=B2BBHw9t; *see also* Jeff St. John, *One Way Data Centers Can Help the Grid? By Being Flexible*, Canary Media (Feb. 27, 2025), https://www.canarymedia.com/articles/utilities/one-way-data-centers-can-help-the-grid-by-being-flexible (reporting that, according to one utility executive, the backlog for connecting large data centers to the grid is now at least five years); Tom Kleckner, *Large Loads Slow to Interconnect in ERCOT*, RTO Insider (Oct. 27, 2025), https://www.rtoinsider.com/118099-ercot-stakeholders-talk-large-loads/ (noting that, of the 130 GW of large load interconnection requests in ERCOT over the past 10 months, "only about 6.5 GW have been energized or approved for energization, with an additional 4.7 GW being studied.").

[35] Author interviews with large load developers; *see also* Old Dominion Electric Cooperative, Comments, FERC Docket No. RM26-4-000, at 9 (filed Nov. 21, 2025) ("[T]he network upgrades necessary to reliably interconnect these new large loads are unprecedented"); Ryan Quint et al., *Practical Guidance and Considerations for Large Load Interconnections*, Grid Lab 14 (May 2025), https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/ ("As more large loads seek connection at higher voltage levels, it can be assumed that the cost of network upgrades will also increase. This is because the cost of transformers, circuit breakers, switchgears, and other interconnecting network devices increases by voltage class."); Transmission Access Policy Group, Comment, FERC Docket No. RM26-4-000, at 6 (filed Nov. 21, 2025) ("[R]apid addition of enormous" large loads will trigger "massive transmission upgrades").

[36] *See, e.g.,* PJM, *2027/2028 Base Residual Auction Report* 3 (Dec. 17, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf (most recent capacity auction cleared 6,516.6 MW short of the reliability requirement); Southwest Power Pool (SPP), Filing, Transmittal Letter, FERC Docket No. ER25-2430-000, at 11 (filed June 4, 2025) (noting that SPP had denied "many Transmission Customers[']" load study requests because the transmission customers lacked sufficient designated resources.); SPP, Filing, Transmittal Letter, FERC Docket No. ER26-1323-000 (filed Feb 10, 2026) (noting that the requirement in SPP for new transmission service applicants to

prevent large customers from obtaining service as a result of lack of adequate network resources. In RTO regions, new large load additions that are not paired with new supply create reliability and cost concerns.[37]

Where new large load customers make flexibility commitments, those commitments can alleviate these concerns. Accordingly, in regulating the large load interconnection process, states should consider rewarding customers who make flexibility commitments in two ways:

1. First, states should consider requiring utilities to prioritize the timing of interconnection studies for flexible large load customers.
2. Second, states should ensure that utility interconnection study processes account for flexibility commitments in the study assumptions.

While some states have active proceedings to consider whether and how to prioritize flexible interconnection customers,[38] we are unaware of any state or utility that has yet administered a workable framework that fully leverages the capabilities of flexibility commitments. This section sets forth a conceptual approach and discusses leading methods that are in development.

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provide sufficient existing or planned generation for a new load "limits the ability of some applicants to obtain firm transmission service for new large loads").

[37] *See* Monitoring Analytics, LLC, *State of the Market Report for PJM* Q3 1, 3 (Nov. 13, 2025), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q3-som-pjm.pdf (*State of the Market Report for PJM*) (finding that inclusion of existing and projected data center load in the peak load forecast caused a $23.1 billion increase in capacity market revenues in PJM over the last three Base Residual Auctions and arguing that "if significant new loads are added without adding new capacity, PJM markets will be less reliable and more costly. New capacity is needed to serve the new loads.").

[38] PA PUC, *Tentative Order: Interconnection and Tariffs for Large Load Customers*, PA PUC Docket M-2025-3054271 (Nov. 6, 2025) (Large Load Tariff Order); Public Utility Commission of Oregon, *Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I*, Public Utility Commission of Oregon Docket No. UM 2377; Public Utility Commission of Texas (PUCT), SB 6 Implementation, PUCT Control No. 58317; VA SCC, *Ex Parte: Electric Utilities and Data Center Load Growth*, VA SCC Case No. PUR-2024-00144.

Prioritizing Flexible Interconnection Requests

Whether and how a utility may prioritize flexible interconnection requests depends on how the interconnection process is administered. The majority of states do not require utilities to establish a formal load interconnection queue process with rules and procedures contained in a tariff.[39] In those states, prioritizing flexible load interconnection may simply mean processing the study requests from customers who have made flexibility commitments prior to processing the requests of other customers.

In many states, however, the accumulation of interconnection requests has prompted a need for formal procedures.[40] Many states have opened proceedings to establish more formal load interconnection procedures.[41] These proceedings are addressing questions such as the size threshold at which customers enter a "large" load interconnection process, site control requirements, financial security requirements, study fees, and whether to process interconnection requests via cluster studies.[42]

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[39] Will Gorman et al., *Transmission Interconnection Roadmap* at 2 n.10 ("Large-load interconnection processes typically exist outside of the traditional generation, storage, and transmission interconnection queues . . . and thus are governed by different, oftentimes idiosyncratic procedures."); Peter Freed & Allison Clements, *How to Reduce Large Load Speculation? Standardize the Interconnection Process*, Utility Dive (Feb. 19, 2025), https://www.utilitydive.com/news/data-center-large-load-interconnection-process-clements/740272/; *see also* PPL Electric Utilities, *En Banc Hearing on Interconnection and Tariffs for Large Load Customers*, Pennsylvania Public Utility Commission (PA PUC) Docket No. M-2025-3054271, Testimony of Joseph Lookup at 2 (filed Apr. 23, 2025) (Lookup Test.) (noting that PPL "inten[ds] to memorialize large load interconnection rules in the retail tariff at some point in the future"); Virginia Electric and Power Company, *Application of Virginia Electric and Power Company for Approval of its Large-Load Connection Queue Process Standards*, Virginia State Corporation Commission (VA SCC) Case No. PUR-2026-00011, Direct Testimony of R. Matthew Gardner at 2 (filed Feb. 2, 2026) (Gardner Test.) (explaining that Virginia Electric and Power Company did not, at the time of filing a proposed load interconnection queue, have a formal queue process).

[40] As Dominion Energy recently explained in proposing new large-load connection queue process standards with the VA SCC, while it was previously "able to manage the fewer number and smaller size of" large load interconnection requests, "without a formal queue process . . . the recent significant increase in the volume of [requests] . . . combined with the increased size of many of the [requests] that represent large load customers, highlighted the need for the Company to develop additional structure to its DP Request process to continue to manage the queue efficiently and transparently." Virginia Electric and Power Company, Gardner Test., VA SCC Case No. PUR-2026-00011, at 2 (filed Feb. 2, 2026).

[41] *See, e.g.,* PA PUC, Large Load Tariff Order, PA PUC Docket M-2025-3054271, at 25 (Nov. 6, 2025).

[42] *See* PUCT, *Memorandum Re: February 20th, 2026 Open Meeting - Agenda Item No. 27 Project No. 58481, Rulemaking to Implement Large Load Interconnection Standards under PURA § 37.0561*, PUCT Control No. 58481 (filed Feb. 13, 2026) (proposing large load interconnection standards, including eligibility requirements, site control and permitting requirements, financial security requirements, and study fees and processes); Virginia Electric and Power Company, *Application of Virginia Electric and Power Company for Approval of its Large-Load Connection Queue Process Standards*, VA SCC Case No. PUR-2026-00011, at P 8 (filed Feb. 2, 2026) (noting, in filing of large load interconnection queue process as required by the VA SCC, that Virginia Electric and Power Company manages delivery point requests

As part of these inquiries, states may consider how to prioritize the interconnection requests of customers who have made flexibility commitments. In states that adopt a cluster study process, utilities could prioritize large customers who make flexibility commitments by advancing their requests to the next cluster to be studied (i.e., placing them ahead of non-flexible customers whose requests were previously submitted). Because flexible large loads have the potential to advance state goals at lower cost and risk to ratepayers, they are not similarly situated to inflexible loads, and prioritizing them should not be deemed undue discrimination.

Accounting for Flexibility Commitments in Interconnection Study Assumptions

State regulators should ensure that flexibility commitments are accounted for in load interconnection study assumptions. While utilities generally do not publish the study assumptions that they use for large load interconnection requests,[43] we understand based on interviews with large load interconnection customers that utilities typically do not account for flexibility commitments in these study assumptions.[44] A common approach is to run studies using the non-coincident peak demand of the large load customer, assuming that the customer could draw that demand at any time, including during system peaks. In this approach, the studies run by the utilities use a baseline of worst-case scenarios, assuming that the power is withdrawn when those withdrawals would place maximum stress on the grid. When that model produces violations of reliability standards, the study concludes that infrastructure must be built to accommodate interconnection. But when a customer has committed to curtail in response to instructions from the grid operator, that flexibility commitment should be included in the study assumptions.[45]

Because existing load interconnection process tariffs filed with state commissions do not generally specify study procedures, utilities and state regulators face a question regarding how much detail to specify with regard to these processes. To ensure that utilities adopt efficient study processes, state regulators can draw from leading-edge examples emerging in some states, as well as from proposals stakeholders have made to FERC in the context of its rulemaking on large load interconnection.

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in batches of 10); *see also* PA PUC, Large Load Tariff Order, PA PUC Docket M-2025-3054271, at 6, 13, 26 (Nov. 6, 2025) (adopting a 50 MW individual and 100 MW aggregate "Large Load Customer" definition, requiring financial security sufficient to cover the cost of any Large Load Customer's share of network upgrades, and proposing that utilities offer biannual Network Open Seasons "which will be analyzed as cluster studies").

[43] Author interviews with large load developers.

[44] *Id.; see also* Miles Farmer et al., Nicholas Federal Load Flexibility Report.

[45] While it may be appropriate to model the lack of curtailment of a flexible commitment as part of an N-1 scenario, similar to modeling a transmission or generation outage under such conditions, we argue that the studies should account for the flexibility commitment in a manner consistent with the capabilities of the customer and how other similarly reliable infrastructure is modeled.

Texas is pioneering a load interconnection study process that may account for flexibility commitments. Senate Bill 6, enacted in June 2025, requires the public utility commission to engage in a rulemaking to implement large load interconnection standards.[46] Commission staff proposed standards, released for comment on February 13, 2026, that require a large load customer to disclose whether it can be modeled as a *Controllable Load Resource* (CLR),[47] which is defined in Electric Reliability Council of Texas (ERCOT) protocols as "[a] Load Resource capable of controllably reducing or increasing consumption under Dispatch control by ERCOT."[48]

ERCOT is in the process of determining how to account for this status in its load interconnection process, but has not yet finalized a new framework.[49] ERCOT "intends to file Revision Requests" to effectuate both a temporary flexibility and permanent flexibility commitment framework. For the temporary framework, ERCOT plans to:

1. "Create a binding framework that would require the Large Load to register as a CLR once operational and remain a CLR until defined exit conditions are met
2. "Include updated [Security-Constrained Economic Dispatch] methodology to ensure the CLR is dispatched to resolve the constraints in real-time operations
3. "Define how CLRs are reflected in other planning assessments to ensure transmission is ultimately built to serve these Large Loads."[50]

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[46] Texas SB 6.

[47] PUCT, *Memorandum Re: February 20th, 2026, Open Meeting - Agenda Item No. 27 Project No. 58481, Rulemaking to Implement Large Load Interconnection Standards under PURA § 37.0561*, PUCT Control No. 58481, at 13 (filed Feb. 13, 2026).

[48] ERCOT Nodal Protocols, § 2 (Definitions and Acronyms).

[49] ERCOT initiated an inquiry into how to account for CLRs in its interconnection process through Planning Guide Revision Request 134, which aimed to "treat the election as a CLR" as a study input, model the site according to the CLR capabilities, and "authorize earlier energization when constraints can be mitigated by dispatch down." ERCOT, *Interconnection Studies Reform for Dispatchable Loads, PGRR134*, (Nov. 1, 2025), https://www.ercot.com/mktrules/issues/PGRR134#background. ERCOT voted to defer action on this proposal in December 2025 and is now in the midst of a series of workshops examining a batch study process for load interconnections. ERCOT, *Batch Study Process for Large Load Interconnections Workshop #2* (Feb. 12, 2026), https://www.ercot.com/calendar/02122026-Batch-Study-Process-for. ERCOT's published timelines at these workshops indicate an intent to present a proposal for ERCOT Board consideration in June 2026. *See* ERCOT, *Large Load Interconnection Batch Study Workshop* 4 (Feb. 12, 2026), https://www.ercot.com/files/docs/2026/02/12/ERCOT-Large-Load-Batch-Study-Workshop-02122026_v06.pptx.

[50] ERCOT, *Large Load Interconnection Batch Study Workshop* 10 (Feb. 12, 2026), https://www.ercot.com/files/docs/2026/02/12/ERCOT-Large-Load-Batch-Study-Workshop-02122026_v06.pptx.

For the permanent framework, ERCOT plans to:

1. "Create a definition that captures the technical requirements needed for some or all of a Large Load to 'never' be seen or served by the grid"[51]
2. "Define the scenarios that still must be assessed in the Batch and other planning studies
3. "Define the allowed modes of participation in the market for the generation with the potential for defined exit criteria
4. "Establish rules preventing the energization of a Large Load studied with new co-located generation until that generation is operational, with the potential for energization of equal amounts of Load as the generation is commissioned."[52]

Together, these changes offer the potential to allow large loads to connect to the system in a manner that recognizes the potential for flexibility commitments to provide a faster path to power and, for customers who make long-term flexibility commitments, reduce infrastructure needs.

Texas holds an advantage over other jurisdictions because within ERCOT the PUCT has unified jurisdiction over retail, wholesale, distribution, and transmission grid operations. Nevertheless, other states can put similar processes in place through their control over the load interconnection process, as well as retail service terms.

For example, states could require that a large load respond to curtailment instructions from its load serving entity and/or, if connected to the distribution system, the electric distribution company. California has pioneered a framework that contains elements of this approach in a California Public Utility Commission (CPUC) "Decision Establishing A Standard Offer for Flexible Service Connections."[53] Building upon approaches developed by two of the state's large investor-owned utilities, Pacific Gas & Electric Company (PG&E) and Southern California Edison (SCE), the CPUC directed the utilities "to establish a standard offer process within the Design and Engineering step of their energization process that establishes an optional Flexible Service Connection agreement for customers affected by distribution capacity constraints."[54] It ordered the utilities to offer interconnection customers the opportunity to accept curtailment during specified time periods while the grid upgrades are pending, to the extent that its interconnection study process finds that

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[51] To permanently reduce infrastructure upgrades, ERCOT's February 12 presentation proposes a bring-your-own-generation framework that involves load not "seen or served by the grid." Per the previous discussion, we argue this is not required to avoid or reduce infrastructure. Rather, a load may rely on the grid for many hours of the year but curtail at key times of constraint.

[52] ERCOT, *Large Load Interconnection Batch Study Workshop* 11 (Feb. 12, 2026), https://www.ercot.com/files/docs/2026/02/12/ERCOT-Large-Load-Batch-Study-Workshop-02122026_v06.pptx.

[53] California Public Utilities Commission (CPUC), *Decision Establishing a Standard Offer for Flexible Service Connections*, CPUC R. 24-01-018 (Feb. 5, 2026).

[54] *Id.* at 2.

there may be constraints during those time periods.[55] While California has offered this approach only on a temporary basis, it could be extended to permanently avoid a need for upgrades.[56]

One limitation states face is that they do not control the large generator interconnection queue, which is overseen by FERC.[57] Thus, without cooperation from FERC-regulated transmission providers, states could not unilaterally create a study approach that streamlines the interconnection of facilities containing both load and generation or storage components that inject into the transmission system to effectuate wholesale sales.[58] However, states could provide for study processes that allow customers to effectuate flexibility commitments using storage or generation resources that have obtained interconnection agreements through FERC-regulated processes. They could likewise provide for similar study processes for infrastructure that does not require FERC-jurisdictional interconnection agreements, such as behind-the-meter generation and storage resources, as well as proximately located distributed resources.[59]

States, in collaboration with FERC and FERC-regulated grid operators, can also develop approaches that involve cooperation between state-regulated utilities and wholesale grid operators. A recent plan outlined by the PJM board in response to the RTO's Critical Issue Fast Path: Large Load Additions stakeholder process detailed an operations framework pursuant to which PJM would cooperate with state-regulated utilities to implement a

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[55] *Id.* at 14 ("The customer agreement for the Standard Offer shall be modeled upon Scenario 2 of the [Limited Load Lift] submitted as Attachment A of PG&E's May 30, 2025 response to the Transparency Ruling."; PG&E May 30, 2025 response (specifying that customers will be informed regarding "an interim solution" providing that "[w]hile the capacity upgrades are being performed, there are certain time periods when [the utility] can accommodate the total requested load. However . . . [d]uring [hours/days/weeks] [the customer] will need to limit the load demand to [insert load limit].").

[56] *See id.* at 37 ("[T]he Standard Offer is a bridging solution."). The CPUC notes that because its offer is only a bridging solution, it does not affect a customer's queue position for full service. A permanent framework could influence queue positions. However, pursuant to the above discussion, in our view priority for flexible customers is warranted due to their mitigation of reliability and affordability concerns for existing customers.

[57] *See supra* in the section on jurisdictional basics under the FPA.

[58] Eolian Energy has proposed study approach for FERC-regulated transmission providers that could enable flexibility commitments to avoid grid upgrades and advance speed-to-power for large customers, in response to FERC's inquiry to consider establishing a large load interconnection process. *See* Eolian, L.P., Comments, FERC Docket No. RM26-4-000, Attach. A: Affidavit of Andrew Levitt, Aniruddh Mohan, Ryan Quint, and Sirisha Tanneeru (Dec. 5, 2025). Disclosure: Roselle LLP filed these comments on behalf of Eolian, L.P.

[59] Virtual power plants (VPPs) at electrically proximate locations could contribute to a customer's flexibility commitments. However, it may be challenging for a customer to aggregate enough distributed resources at electrically proximate locations sufficient to alleviate a large load customer's impact on distribution or transmission grid constraints. VPPs are potentially a more promising solution to generation capacity constraints, which may be relevant to queue priority (discussed previously), as well as BYOC programs.

curtailment framework.[60] This framework addresses PJM capacity market shortfalls as a result of the growth of large loads. A similar framework could be developed to effectuate curtailment responsive to flexibility commitments such that the curtailments could provide inputs to both FERC-regulated and state-regulated interconnection processes. PJM sets forth a role for itself and for state-regulated utilities:

> *"Ultimately, the determination of which loads are curtailed during emergency conditions rests with TOs [Transmission Owners], and with LSEs [Load Serving Entities] that have direct relationships with their customers. PJM does not have authority to direct individual retail loads to curtail demand. However, PJM will establish an allocation framework whereby TOs and LSEs have advanced notification of the potential magnitude of load reductions that may be required under such conditions. PJM intends to explore how to design curtailment allocations based on the contributions of any shortfall to PJM's required reserve margin."*[61]

One way a state interconnection process could be developed in collaboration with a FERC-regulated RTO to enable flexible large loads would be for the state-regulated interconnection agreement require that the large load curtail when the RTO issues instructions to do so in response to a grid constraint. By requiring the RTO-instigated curtailment in a state-jurisdictional agreement, the large load customer is obligated to curtail even though the RTO could not have required it to through its FERC-jurisdictional tariff. A coordinated state-federal framework would thus enable the load serving entity to be responsive to the RTO curtailment by curtailing particular large load customers, without requiring curtailment of any of its other customers.

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[60] *See* David E. Mills, *Board Decisional Letter on Critical Issue Fast Path – Large Load Additions* 4–5 (Jan. 16, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf (PJM Board CIFP Decision) (setting forth PJM's proposal for "connect-and-manage" for large load additions).

[61] *Id.* at 5.

RATEMAKING

Background

The FPA preserves state authority to regulate rates for distribution service and retail energy sales.[62] Additionally, while states cannot alter or deny recovery of FERC-jurisdictional charges for transmission, wholesale energy, and capacity,[63] states are generally responsible for allocating those costs across retail customer classes, including large load classes.[64]

Utility ratemaking centers on formulating rates that enable recovery of the utility's revenue requirement while equitably balancing cost burdens across customer classes (residential, commercial, and industrial). For large load customers, the utility bill typically has three broad components:

1. A customer charge, which is a flat charge scaled to each rate class that is meant to recover costs that do not vary with demand, such as billing, metering, etc.
2. A series of demand charges for distribution service (for distribution-connected loads), transmission service, generation (capacity), and ancillary services, all of which vary across billing cycles based on measured peak demand (kW),[65] occasionally with a time-varying rate
3. Energy charges, which are a product of the volume of energy consumed (kWh), and in some instances apply a rate that varies based on time of use

In restructured states, if the load chooses a competitive supplier, some components of the bill—principally the energy and capacity portion of the demand charges—would be determined competitively and billed separately from the wires components.

The data center boom is shaping state ratemaking decisions across the country. While many states leave utilities free to negotiate terms with new large loads,[66] states are increasingly requiring utilities to implement large load tariffs that provide standard terms for the largest loads—typically those that exceed 25 to 100 MW.[67] In advancing large load tariffs, states

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[62] 16 U.S.C. 824(b).

[63] *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986); *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988).

[64] *PJM Interconnection LLC*, 193 FERC ¶ 61,217, at P 210 n. 440 (2025) ("[S]tates have exclusive authority over the allocation of Commission-jurisdictional costs to retail customers.").

[65] Demand charges are often billed based on the highest non-coincident peak usage on the customer meter over 15- or 30-, 60-minute interval. Many demand charges also contain a comparatively small volumetric component.

[66] *See* Eliza Martin & Ari Peskoe, *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power* 11–14 (2025), https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf (*Extracting Profits from the Public*).

[67] *See* Smart Electric Power Alliance, Database of Emerging Large-Load Tariffs (DELTa), https://sepapower.org/large-load-tariffs-database/.

have sought to prevent new large loads from shifting costs to other ratepayers by addressing two types of risks: *stranded asset risk* (the risk that the new large load will fail to generate utility revenue that justifies the infrastructure needed to serve it) and *repayment risk* (the risk that, even if a load is subject to take-or-pay provisions, it won't be solvent when the bill comes due). Stranded asset risk has led many state regulators to advance minimum monthly demand charges, minimum contract lengths, and exit fee provisions. Repayment risk has led many utilities and state regulators to impose collateral requirements and to expand the scope of infrastructure projects for which large loads pay directly during construction, either through CIAC or other upfront payment requirements.

Equitable Rates for Flexible Large Loads

Rates charged to flexible large loads should reflect their distinct cost causation and risk profile. Without separate rate treatment, flexible large loads will pay for a greater share of infrastructure investments than they are responsible for—in effect, cross-subsidizing inflexible large loads. By creating a separate rate class for flexible large loads, the regulator's goal should not be to subsidize flexible large loads. Rather, the goal should be to achieve rates that are fair and that provide an accurate price signal for large loads considering investments in energy storage and other technologies that would enable them to qualify as a flexible large load.

A starting point for determining fair rates for flexible large loads is the fact that many of them use and benefit from the grid like their inflexible counterparts. Thus, flexible large loads should have to pay for embedded system costs on equal terms as other large loads.[68] But to the extent they avoid new system costs through their commitments to flexible operations, flexible large loads warrant different rate treatment. Table 2 describes how the flexibility commitments made by flexible large loads can affect the key cost drivers that compose utility revenue requirements:

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[68] The primary use case this paper contemplates, given the sources of recent large load growth, is high-load-factor flexible data centers. However, differential rate treatment with regard to embedded costs may appropriate for low-load-factor flexible large loads, such as thermal storage, depending on the rate structure used to recover such embedded costs. This is because low-load-factor loads can facilitate greater grid utilization rates and allow a larger amount of demand to use the existing system.

Table 2. Flexibility Impacts to Utility Cost Drivers

Cost Driver	Impact of Flexibility
Distribution	Large load flexibility commitments can reduce distribution costs by avoiding the need for distribution system upgrades when curtailment is available at the direction of the distribution utility.
Transmission	Large load flexibility commitments can reduce transmission system network upgrades and local transmission needs when curtailment is available at the direction of the transmission owning utility and/or the RTO/ISO system operator. Where a flexible large load can take non-firm transmission service through its LSE rather than Network Integrated Transmission Service,[69] the flexible large load can reduce total transmission costs allocated to the LSE. Where regional transmission expansion studies incorporate flexibility commitments, the flexible large load may reduce required transmission build and/or cost allocated to its zone.
Capacity	Where capacity requirements are imposed through RTO/ISO tariffs, large load flexibility commitments can reduce capacity costs if flexibility is considered in calculating each balancing authority's capacity obligation and/or if the flexible large load curtails in a way that reduces measured demand during peak load assessment intervals. Where capacity requirements are determined solely under state requirements, such as through integrated resources plans, state regulators can recognize the capacity value of large load flexibility commitments and thereby reduce the need for new generation.
Energy	Flexibility can enable large loads to reduce consumption during times when energy prices are highest.

How Flexibility Should Inform Large Load Rate Components

Direct Assignment of Network Upgrade Costs

When large loads interconnect, two types of facilities must be built. *Interconnection facilities* are those on the customer side of the point of interconnection, which therefore accrue solely to the benefit of the interconnection customer. Interconnection facilities are paid for by the customer at the time of construction through CIAC. Because they are directly assigned and paid through CIAC, interconnection facility costs are not part of the utility rate base and are not recovered in distribution or transmission rates. The second type of

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[69] Although the outcome of the proceeding remains unclear as of this writing, FERC has required PJM to offer non-firm contract demand transmission service to co-located loads. *PJM Interconnection, LLC*, 193 FERC ¶ 61,217 at P 160. SPP has also proposed tariff revisions to establish a temporary Conditional High Impact Large Load Service that would allow customers that would otherwise be prevented from interconnecting by the need for network upgrades or additional designated resources to obtain "as-available" transmission service for a period of up to seven years. *See* SPP, Filing, Transmittal Letter, FERC Docket No. ER26-1323-000 (filed Feb. 10, 2026). This proposal is also pending as of the time of publication.

facilities are *network upgrades*. This is a loose term that can have different meanings in context. Generally, network upgrades are located on the utility side of the point of interconnection and may have any number of beneficiaries. Historically, network upgrade costs necessary to interconnect large loads have been added to rate base and socialized across the utility footprint.[70] Increasingly, however, a diverse range of policymakers have sought to ensure that network upgrade costs for new data centers should be allocated entirely to the data centers themselves.[71]

There are different approaches, however, to how utilities could fulfill the broadly-stated objective of allocating all network upgrade costs to the data centers. In one approach, network upgrades are rolled into rate base and reflected in the distribution and transmission rates allocated to the large load rate class.[72] In that approach, the utility conducts a cost of service study that aims to make new large loads pay for their network upgrades as a class, but each individual large load does not pay for the upgrades it causes itself. In another approach, network upgrades are directly assigned to the interconnecting load and paid through CIAC (a non-refundable charge) or through upfront payments that are refundable based on billing to the large load and/or subsequent use of the same upgrades by other large loads.[73]

For example, the Pennsylvania Public Utility Commission (PUC) recently proposed that interconnecting large loads pay the cost of any network upgrade from which it would receive more than half the benefit through CIAC.[74] The PUC observed that data center loads have gotten so big that some upgrades, such as 230 kV facilities that would have historically been

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[70] *See* Abraham Silverman et al., *Can Regulators Protect Small Customers from Rising Transmission Costs for Big Data Centers?* Utility Dive (Dec. 11, 2024); Eliza Martin & Ari Peskoe, *Extracting Profits from the Public*, at 5–10.

[71] *See, e.g.,* DOE ANOPR at P 25 ("load and hybrid facilities should be responsible for 100% of the network upgrades that they are assigned through the interconnection studies").

[72] *See, e.g.*, VA SCC, *Final Order: Application of Virginia Electric and Power Company*, VA SCC Case No. PUR-2025-00058, at 25 (approving Dominion Energy's proposed Rate Schedule GS-5, to be effective January 1, 2027, for large customers, including minimum demand charges for distribution, transmission, and generation based on percentages of contracted demand); *see also* Duke Energy Florida, *Petition for a limited proceeding to approve large load tariff by Duke Energy Florida, LLC*, Florida Public Service Commission, Docket No. 20250113-EI, Direct Testimony of Steven W. Wishart at 27 (filed Sept. 5, 2025).

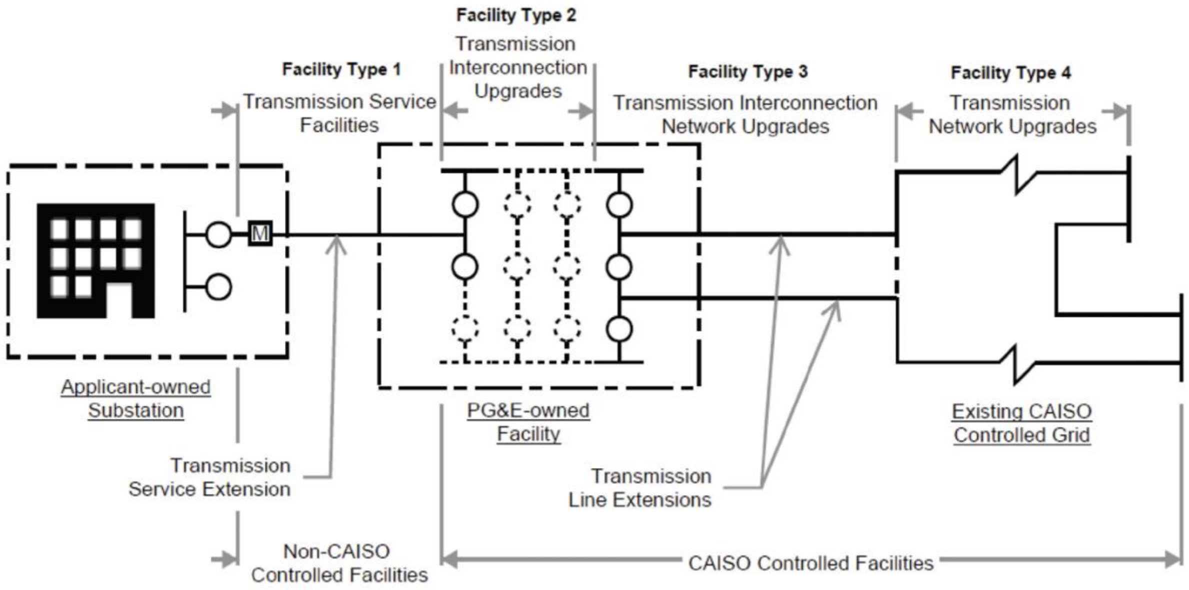
[73] *See* PPL Electric Utilities, Lookup Test., PA PUC Docket No. M-2025-3054271 at 2 (filed April 23, 2025) ("[H]yperscalers and their load often require upgrades to the 500 kV and 230 kV bulk electric system, which benefit not only these customers directly but also the transmission and distribution system as a whole . . . . Consequently, when determining cost allocation, PPL Electric evaluates necessary system upgrades and segregates the costs into customer-specific costs which will be paid through a contribution in aid of construction ('CIAC') and costs that will be socialized through rates. This case-by-case determination is based on whether the specific upgrade provides reliability benefits to the grid as a whole or if it only benefits the new customer.").

[74] PA PUC, Large Load Tariff Order, PA PUC Docket M-2025-3054271, at 16 (Nov. 6, 2025).

allocated broadly, now may be properly allocated to a single customer.[75] Where a large load triggers the need for a network upgrade and derives most, but not all, of the benefit, states may consider approaches where the triggering load pays the upfront cost and is partially refunded as other beneficiaries make use of the common facilities.

In a proceeding now pending before the CPUC, PG&E has proposed an approach that breaks the transmission facilities needed to serve new large loads into four categories, shown in Figure 1. PG&E has proposed that the new large load pay upfront for type 1–3 facilities, subject to refund, but not type 4.[76]

Figure 1. Illustrative diagram of transmission facility types



Source: CPUC, Decision 25-07-039, Application 24-11-007, at 9 (July 24, 2025).
Note: Dashed lines represent potential future transmission interconnection upgrades.

The CPUC has allowed PG&E to proceed on an interim basis with some aspects of PG&E's proposal, but the question of cost responsibility, particularly for type 4 facilities, remains pending.

Directly assigning customer-specific network upgrade costs to be paid through CIAC or through refundable upfront payment is a good practice for protecting against cost shifts to other customer classes. Direct assignment also provides the right set of price signals for load flexibility, because it allows interconnecting loads to optimize the trade-off between investments in flexibility and avoided infrastructure. Further, as explained in following

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[75] *Id.*

[76] CPUC, *Decision 25-07-039*, Application 24-11-007 (July 24, 2025).

sections, by removing the cost of network upgrades that narrowly benefit specific large loads from rate base, state regulators can greatly simplify the task of achieving rates that avoid cross-subsidies between flexible and inflexible large loads.

Distribution and Transmission Demand Charges

How state regulators approach distribution and transmission demand charges for flexible large loads should depend on the extent to which incremental distribution and transmission infrastructure are rolled into rate base. If all distribution and transmission upgrades triggered by large loads are directly assigned to the interconnecting loads, the distribution and transmission demand charges would only recover embedded grid costs, in which case it would generally be appropriate for flexible large loads to pay the same demand charge rate as inflexible ones.[77] As discussed, flexible large loads that are appropriately studied based on their commitments to be curtailable will trigger less extensive upgrades, while inflexible large loads will cause the need for, and directly pay for, more expansive infrastructure upgrades.

On the other hand, if network upgrade costs for new large loads are broadly socialized or allocated to the large load class as a whole, then the state regulator may conduct an inquiry to ensure that flexible large loads are assessed lower distribution and transmission demand charges to reflect that, on average, they require fewer such upgrades.

Generation Demand Charge/Capacity Charges

Utilities typically apply a generation demand charge to recover capacity costs. The charge may be in the applicable tariff or in a separate rider that is adjusted to reflect changing regional capacity prices. There is no reason to establish a generation demand rate paid by flexible large loads that is different from the rate paid by inflexible large loads, because the utility's cost of providing capacity on a unit basis will typically be the same for all types of loads. However, it would likely be appropriate to adjust the base demand (kW) to which the rate is applied. In an extreme case, where a new large load is non-capacity-backed,[78] it should see no capacity demand charge at all. In vertically integrated states, the interconnecting utility may have some discretion, under regulatory supervision, to determine how much capacity must be acquired to serve a new flexible large load. In such cases, the utility may determine that the new load's flexibility commitments mean that it can

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[77] Per the discussion in n. 68, low-load-factor loads may merit a lower rate even in this case, depending on the rate structure.

[78] In Fall 2025, PJM proposed in a set of rule changes as part of its Critical Issue Fast Path stakeholder process that would designate some new large loads as *non-capacity backed* loads. Tim Horger, *Large Load Addition: PJM CIFP Initial Proposal and Alternatives Considered* (Sept. 15, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20250915/20250915-item-07---pjm-initial-proposal-and-alternatives-considered---pjm-presentation.pdf. That proposal was withdrawn. Tim Horger, *Large Load Addition: CIFP Update* (Oct. 1, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251001/20251001-item-04---cifp---lla-updates---pjm-presentation.pdf. Recently, PJM's board proposed an approach it calls *connect-and-manage* for new large loads that do not acquire their own new generation. *See* David E. Mills, PJM Board CIFP Decision at 3–5.

interconnect without any new generation capacity or with less than a megawatt-for-megawatt ratio of new generation to new load, depending on how the flexibility commitment is accredited. Fairness would thus require reducing the flexible large load's generation demand charge proportionally.

Minimum Demand Charges

To protect against stranded asset risks, many utilities require new large loads to pay minimum demand charges for each billing cycle of the contract term. These minimum demand charges are typically calculated as the product of the large load's contract capacity,[79] a percentage set forth in the tariff or through negotiation (e.g., 80%[80] or 85%[81]), and the sum of all demand-denominated ($/kW) tariff rates and riders for which the large load is liable. Whether the minimum demand charge percentage should be the same for flexible large loads as for other large loads ought to depend on how the demand charges that go into it have been determined. If the individual demand charges (distribution, transmission, generation/capacity, etc.) are determined in a way that reflects the cost causation profile of the flexible large load (as discussed), then flexible large loads should be subject to the same minimum demand charge percentage as their inflexible counterparts. If not, then state regulators should consider lowering the flexible large load's minimum demand charge percentage to reflect its lower stranded asset risk.

Minimum Contract Period and Early Termination Fees

Utilities and state regulators are increasingly requiring new large loads to enter minimum contract periods (often 5–12 years)[82] and to pay early termination/exit fees if they are unable to perform over the entire period. Flexible large loads also require long-term infrastructure commitments and thus should be subject to the same minimum contract periods as their inflexible counterparts. Whether they should be liable for the same early termination fee as their inflexible counterparts ought to depend on how that termination fee is calculated. Where the early termination fee is calculated as a multiple of the minimum

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[79] "Contract capacity" in large load tariffs is typically defined as the mutually agreed peak demand requirement of the large load, after the conclusion of any ramp period. *See, e.g.,* Ohio Power Company, P.U.C.O. No. 21, Original Sheet No. 223-1, Schedule DCT (Data Center Tariff), https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/March_2026_AEP_Ohio_Tariff_Book.pdf (Data Center Tariff).

[80] *See* Indiana Michigan Power Company, Schedule of Tariffs Governing the Sale of Electricity in the State of Indiana, I.U.R.C. No. 20, Original Sheet No. 21.5, Tariff I.P. (Industrial Power), https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_03-02-2026.pdf.

[81] *See, e.g.,* Ohio Power Schedule Company, Data Center Tariff, Original Sheet No. 223-3.

[82] *See* Rocky Mountain Institute, *Large Energy Users Want Power. Here's How to Protect Other Ratepayers from the Costs* (2025) Exh. 2 (displaying range of contract lengths, calculating average of 10.9 years in post-2024 large load tariffs), https://rmi.org/large-energy-users-want-power-heres-how-to-protect-other-ratepayers-from-the-costs/.

demand charge (e.g., 36 months of minimum charges[83] or the remaining minimum demand charges on the contract[84]), and the underlying demand charges reflect the cost causation profile of the flexible large load, then there is no reason to differentiate between flexible and inflexible loads. Where that is not the case, state regulators should consider lowering the early termination fee for flexible large loads to reflect the fact that they require less infrastructure and therefore pose a lower stranded asset risk.

Collateral/Security Requirements

To ensure repayment, many utilities and state regulators insist that interconnecting large loads post collateral over the entire contract period. Collateral requirements begin with a base collateral amount, which may be a fixed amount (i.e., $1.5M/MW[85]) or a multiple of minimum demand charges (e.g., 50% of all remaining minimum demand charges[86]). In some cases, the base collateral amount is then reduced based on the creditworthiness of the interconnecting load or its guarantor, and decreases linearly over the minimum contract period. As with early termination fees, whether collateral requirements are adjusted for flexible large loads should depend on how they are structured. If the base collateral amount is a simple multiple of minimum demand charges that reflect the cost causation profile of the flexible large load, then there is no reason for the flexible and inflexible loads to face different collateral requirements. If the base collateral amount is based on a simple multiple of contract capacity, however, then state regulators should consider reducing the base collateral amount for flexible large loads to reflect the fact that they will on average create lower levels of stranded asset risk per megawatt of contract capacity.

Energy Rates

Generally, there is no reason for flexible and inflexible loads to pay different rates for energy. However, states can and should promote flexible operations in the way they structure energy rates for large loads. In states where large loads cannot choose a competitive provider (or in setting standard offer service rates in states where they can), state regulators should consider forcing all large loads onto market-based[87] or time-of-use

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[83] *See, e.g.,* Ohio Power Schedule Company, Data Center Tariff, Original Sheet No. 223-5.

[84] *See* Consumers Energy Company, M.P.S.C. No. 14 – Electric, Original Sheet No. D-67.50, Large General Service Primary Demand Rate GPD, https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf.

[85] *See, e.g.,* VA SCC, *Final Order: Application of Virginia Electric and Power Company*, Case No. PUR-2025-00058, at 25 (approving Dominion Energy's proposed Rate Schedule GS-5, to be effective January 1, 2027, for large customers including collateral requirements).

[86] *See, e.g.,* Ohio Power Schedule Company, Data Center Tariff, Original Sheet No. 223-5.

[87] *See, e.g.,* Virginia Electric and Power Company, Schedule MBR, Large General Service Market-Based Rate, § II.B.1.b, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/content/rates-and-tariffs/pdfs/virginia/shared/entire-filed-tariff.pdf?rev=4717a57ce7fa427996787a8de34536e1&hash=5EF3D8DD6FA0FB54E8AD04E95060D276

rates[88] to incentivize flexible operations. Exposing large loads—typically sophisticated market actors—to time-variant pricing, especially during system peaks[89] when prices spike, will incentivize flexible operations on the margin. Flexible large loads will have the greatest capacity to shift consumption in response to real-time pricing, but even large loads that are not designed for flexibility may have some capability to shift workloads temporally or geographically during high-price periods.

PLANNING

If properly integrated into planning, large load flexibility commitments could reduce planning challenges faced by state regulators and utilities in integrating large loads and limit the risk of stranded infrastructure investments. A defining challenge of the current load growth boom is that regulators and utilities do not know how big it will be. A few short years ago, AI and data centers were a footnote to the utility planning discussion; today they are central.[90] Current forecasts vary widely, making it challenging to determine how much infrastructure to build.[91] Because infrastructure construction is so time-consuming, processes must initiate investments based on best guesses, creating a risk of stranded costs.[92] Load flexibility commitments are a powerful tool to address this challenge. By

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(linking energy rate to hourly PJM day-ahead locational marginal price for the load zone where the load is located); *see also* Otter Tail Power Co., Thermal Market Energy Pricing Rider, https://puc.sd.gov/commission/tariffs/Electric/ottertail/section14/16.pdf. Market-based tariffs can also provide the utility a valuable hedge against energy price volatility, at least up to the volume the utility is net short in the energy market.

[88] *See, e.g.,* Consumers Energy Company, M.P.S.C. No. 14 – Electric, Original Sheet No. D-59.00-60.00, Large General Service Primary Demand Rate GPD, https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf (establishing on-peak and off-peak rates for both summer and winter periods).

[89] *See* PG&E, Electric Schedule B-20, Service to Customers with Maximum Demands of 1000 Kilowatts or More, Cal. P.U.C. Sheet No. 61081-E, Sheet 4, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_B-20.pdf (applying energy rate of $0.90/kWh for large loads during peak-day pricing events called by the utility).

[90] *See* John D. Wilson et al., Grid Strategies Upward Revision Report 3–4 (noting that "the 5-year forecast of utility peak load growth has increased by more than a factor of six, from 24 GW to 166 GW" from 2022 to 2025, driven in significant part by data centers).

[91] *See* Scott Nystrom, *Shouldering the Load: Uncertain Demand for Electricity Presents Challenges and Opportunities*, Climate Leadership Council (Nov. 19, 2025), https://clcouncil.org/blog/shouldering-the-load/ (surveying eight load growth estimates and finding that "[t]he variance between estimates equals the total demand of TX, CA, FL, and the 21 next largest load states").

[92] Energy & Environmental Economics, *Forecasting Large Loads in the Age of AI and Data Centers* (Dec. 9, 2025), https://www.ethree.com/forecasting-large-loads/ (*Forecasting Large Loads*) ("Today, assuming that AI-driven load growth will rise indefinitely creates a similar risk" to the stranded assets that occurred when electricity demand flattened after sustained growth in the 1970s and whose costs were carried by customers. "The uncertainty runs in both directions: overforecasting can drive

eliminating or reducing infrastructure needs to serve new large loads, they reduce the risks that come from getting forecasts wrong. In contrast to traditional demand-response programs, load flexibility commitments can be planned into the initial siting and interconnection of large loads, ensuring that flexibility commitments can be relied upon in times of peak stress on the grid. To achieve this outcome, however, states can and should improve the use of load forecasting and planning processes to identify, quantify, and ultimately plan and implement the promise of load flexibility.

All power sector planning processes begin with load forecasts developed by utilities, RTOs, ISOs, and certain regulatory bodies to predict the resource needs in the coming years. States play an important role in utility planning, which varies with the specific regulatory framework. In vertically integrated states, and increasingly even in some non-vertically integrated states, utility commissions oversee integrated resource planning processes.[93] States also oversee load forecasting processes that provide inputs into utility investment decisions. Such forecasts guide distribution and transmission spending within individual utility service territories, and serve as inputs into regional infrastructure planning processes.[94] Even in restructured states, forecasts may guide state-regulated procurements, influence merchant investment decisions, and inform regional capacity planning.

Load forecasting processes have historically used regression models based on historical trends, demographic shifts, macroeconomic indicators, and weather data.[95] These historic

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unnecessary capital investment and higher rates, while underforecasting can create reliability constraints and impede economic development."); Rachel Mural et al., *AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment*, Harvard Belfer Center for Science and International Affairs 2–4 (Feb. 2026), https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf.

[93] *See, e.g.,* CT Gen Stat § 16a-3a; 220 ILCS 5 §§ 16-201 & -202; S.C. Code of Laws Section § 58-37-40; Utah Code Ann. § 54-17-301.

[94] *See, e.g.,* California Independent System Operator (CAISO), *CAISO Response to Chairman David Rosner's 09/19/2025 Letter re Large Load Forecasting for America's Significant Electricity Demand Growth* 1 (Oct. 13, 2025), https://www.ferc.gov/media/caiso-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas; New York Independent System Operator, Inc. (NYISO), *NYISO Response to Chairman David Rosner's 09/19/2025 Letter re Large Load Forecasting for America's Significant Electricity Demand Growth* 2 (Oct. 31, 2025), https://www.ferc.gov/media/nyiso-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas; PJM, *PJM Manual 19: Load Forecasting and Analysis*, Revision: 38, at 12, 14, & Attach. B (Dec. 17, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf; SPP, *SPP Response to Chairman David Rosner's 09/19/2025 Letter re Large Load Forecasting for America's Significant Electricity Demand Growth* 2–4 (Oct. 10, 2025), https://www.ferc.gov/media/spp-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas.

[95] Juan Pablo Carvallo et al., *Long Term Load Forecasting Accuracy in Electric Utility Integrated Resource Planning*, 119 Energy Policy 410, 417 (Aug. 2018); ESIG, *Forecasting for Large Loads* at 2; *see also* ISO New England, *Forecast Modeling Procedure for the 2019 CELT Report: ISO New England Long-Run Energy and Seasonal Peak Forecasts* 1, 3, 6 (Apr. 30, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/modeling_procedure_2019.pdf; Midcontinent Independent System Operator,

processes, however, are proving inadequate for this new era of load growth from large concentrated loads, creating a high degree of uncertainty.[96] Utility planners currently use economic and population growth as one input into their forecasting models, but growth from large loads does not directly correlate to those metrics. The process of integrating new large, concentrated loads also lacks historical data that forecasters would typically use. The data that are available also tend to be unreliable because they are based upon opaque interconnection requests and can include redundancies due to large load applications spanning multiple jurisdictions.[97]

Therefore, before any planning processes can adequately incorporate proactive flexibility commitments, state policymakers must ensure that the base forecasting captures the demand projections adequately. Because of the urgency of the moment, many jurisdictions are pressing to improve these processes, including by demanding improved data about incoming loads[98] and carving out and independently assessing large loads in their forecasting processes.[99] Active collaboration and data sharing between regulators and utilities is also increasing both to create common forecasts of large load growth and control for redundancies and inconsistencies between jurisdictions.[100]

The recent work undertaken by ESIG provides a detailed guide for incorporating flexibility into state-jurisdictional forecasting and planning. One recent ESIG report, *Forecasting for Large Loads: Current Practices and Recommendations*, provides a cogent synthesis of how to update forecasting practices to better capture the impact of large loads.[101] The report offers five key metrics that should be used to create a large load forecast:

1. *Project realization*, or the rate at which projects included in the load forecast are placed into service
2. *Energization date*, or the date at which a load is forecast to begin commercial operation, including anticipated delays

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Inc., *Long-Term Load Forecast*, 3, 11, 16 (Dec. 2024), https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf; PJM*, 2025 Long-Term Load Forecast Supplement* (Jan. 2025), https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-long-term-load-forecast-supplement.pdf.

[96] Louisa Eberle & Camille Kadoch, *Building Resilient Foundations for Large Loads*, Regulatory Assistance Project 25 (Feb. 2026), https://www.raponline.org/wp-content/uploads/2026/02/rap-eberle-kadoch-building-resilient-foundations-large-loads.pdf (*Building Resilient Foundations for Large Loads*).

[97] ESIG, *Forecasting for Large Loads* at 2–3; *see also* Ryan Quint et al., *Assessment of Large Load Interconnection Risks* at 11; Energy & Environmental Economics, *Forecasting Large Loads in the Age of AI and Data Centers* at 6.

[98] *See* Texas SB 6.

[99] *See* David E. Mills, PJM Board CIFP Decision, App. B.

[100] Louisa Eberle & Camille Kadoch, *Building Resilient Foundations for Large Loads* at 13–16.

[101] ESIG, *Forecasting for Large Loads*.

3. *Load realization*, or the forecast peak load that the project is expected to require once it is fully scaled
4. *Load ramping*, or the monthly or annual forecast of demand during the startup period of commercial operation
5. *Load factor* or *load shape*, which is either the actual energy use as a proportion of facility capacity (load factor) or a more detailed schedule of usage over time

In creating these metrics, ESIG observes that current practices can blend the metrics in a manner that obscures the transparency needed for planning purposes. One example is the combination of the project realization and load realization metrics, leaving it unclear which metric is affecting forecasts. Another example of where clarity could be increased was the use of on-site generation by large loads and its resulting impact on load realization, ramping, factor and shape.[102]

ESIG also acknowledges that forecasters should ideally include load flexibility commitments as a key metric in forecasting, but notes the difficulty in using standard practices for considering load flexibility in forecasts and planning models. Nonetheless, as states begin to utilize the tools described in the report to encourage large load flexibility, they will be able to capture flexibility commitments with a greater degree of certainty and reliability.

ESIG also recently released a second report focused on the integration of large load flexibility commitments into planning processes, and addressing some of the concerns raised in the prior report. The new report sets out a stepwise approach to tackling the challenge, suggesting that planners could follow the methodology to allow for proactive incorporation of flexibility in their planning processes. In this instance, ESIG suggested six steps to ensure large load flexibility potential is embedded in plans:

1. **Detailed characterization of the loads.** Rather than simplified characterization of a new load's basic characteristics, large loads should be more finely characterized to account for characteristics such as their size, onsite backup generation, flexibility capability, and price responsiveness to allow planners to better appreciate their potential resource adequacy contributions.
2. **Improve the forecasts.** Beyond the earlier recommendations, ESIG also clarified that forecasts should disaggregate large loads from other parts of the load forecast and evaluate a range of scenarios.
3. **Set baseline by quantifying capacity requirements of large loads absent flexibility.** This step sets the default requirements without flexibility as a reference against which planners can evaluate the ability for flexibility to forego capacity requirements.
4. **Quantify the potential capacity contributions of large load flexibility.** As compared to the third step, planners should evaluate the potential capacity contributions from a large load—if it is flexible. As a result, planners will determine the capacity accreditation for large load flexibility.

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[102] *Id.* 33.

5. **Calculate the avoided infrastructure investment required from large load flexibility.** By comparing the outputs from step 3 and step 4, planners can determine the avoided capacity need, avoided costs, and avoided emissions that can be realized with large load flexibility.
6. **Develop a regulatory framework that ensures large load flexibility will deliver resource adequacy.** This step simply acknowledges that once planners have isolated the benefits of flexibility up front in the planning process, they are able to use the regulatory tools described throughout this report to secure those benefits.

We cannot plan for what we cannot predict, and we cannot execute investments that are not included in the plan. Thus, if states want to take advantage of the opportunity that load flexibility provides, accurate forecasting and planning are essential. The processes described above will allow regulators to achieve the proactive vision they need to harvest these benefits for the power systems.

BRING-YOUR-OWN-CAPACITY

Overview of Bring-Your-Own-Capacity Frameworks

States are increasingly considering bring-your-own-capacity or bring-your-own-generation requirements as an additional tool to control the costs and risks of accelerating demand from large loads.[103] BYOC frameworks aim to ensure that the addition of supply better matches the pace of load additions, in light of the general tendency for loads to be developed and interconnected faster than new capacity. BYOC frameworks may encourage economic development where the grid operator is struggling to connect new supply quickly enough to meet growing demand, motivating large load customers to develop facilities that require less new generation or to procure capacity that can be more rapidly developed than traditional large resources. Further, by incentivizing or requiring large loads to procure new supply to meet their needs, states mitigate the risk of price spikes and reliability concerns that could otherwise impact all ratepayers when supply additions lag behind demand growth. BYOC frameworks, however, go beyond minimum billing obligations or other rates structures that seek to ensure large loads bear their own risks and costs and prevent shifting to other customer classes. By tying eligibility for rates or services to capacity procurement, a large load's ability to commence operation becomes directly dependent on the timing of development of new capacity, placing the risks of delays on large loads.

BYOC frameworks may be voluntary or mandatory. Voluntary BYOC frameworks depend on incentives such as access to expedited interconnection or preferred rates or services (e.g., access to firm transmission service rather than interruptible service). In general, speed-to-power is recognized as one of the strongest incentives for large load participation in

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[103] For example, state representatives from throughout the PJM footprint advocated for PJM to require data centers to BYOC or face limits on service. PJM Legislators Collaborative, *Letter to David E. Mills, Manu Asthana, and the PJM Board of Directors* (Nov. 17, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20251118-pjm-legislators-collaborative-letter-re-cifp-lla.pdf ("the BYOC requirement will prevent unacceptable capacity and energy cost shifts to the public and isolate reliability problems to the appropriate utility areas.").

voluntary frameworks.[104] Mandatory BYOC frameworks deny large loads access to service—for example, by denying interconnection or retail service—until a large load demonstrates the requisite procurement of capacity.

BYOC frameworks only function where the state regulator has the jurisdiction and authority to deny or delay access to service. While most load interconnections currently remain state-jurisdictional, federal assertion of jurisdiction over large load interconnections would change that, limiting the reach and effectiveness of state BYOC requirements. Likewise, requiring curtailment as a consequence of failing to procure sufficient capacity may depend on coordination across multiple entities that play a role in establishing curtailment rules. In contrast, state utility regulators commonly have plenary authority over retail service. Legislatures seeking to ensure a state regulator has sufficient authority to implement a BYOC framework may clarify or shore up the regulator's authority to deny service to the defined class of large loads under particular conditions (e.g., where the large load fails to procure a regulator-defined level of capacity). To support timely development of large loads, legislatures may also seek to pair such limits on access to service by affording such large loads the opportunity to procure capacity through means other than through the electric utility (e.g., through development of on-site generation or procurement through competitive suppliers).

Apart from these jurisdictional questions, BYOC frameworks are effective only to the extent they apply to a sufficient share of the market. For example, in centralized regional capacity markets such as those in the eastern RTO/ISOs, requiring that large loads located in a subset of the market bring their own capacity may not completely mitigate the price impacts caused by accelerating load growth if unmatched supply additions persist in other areas covered by the same capacity market. Market fundamentals in the region determine shortage conditions, with single-state efforts having limited impact on those dynamics.[105]

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[104] *See* CAISO, Comments, FERC Docket No. RM26-4-000, at 12 (filed Nov. 21, 2025) ("An expedited process would appropriately incentivize more developers to consider curtailable and dispatchable facilities, which ultimately will benefit large loads, the grid, and ratepayers."); David Gardner and Associates, Comments, FERC Docket No. RM26-4-000, at 6 (filed Nov. 21, 2025) ("DGA recommends that such incentives should focus on speed to power rather than market payments time is money and there is more leverage in providing an incentive to interconnect quicker (whether through a new load interconnection process or via the generation interconnection process) than there is in potential future market payments.); Emerald AI, Comments, FERC Docket No. RM26-4-000, at 1 (filed Nov. 21, 2025) ("We . . . . urge the Commission to . . . reward[] verifiable flexibility with what large loads value most: faster and larger interconnections for new facilities seeking swift access and existing facilities seeking larger and speedy capacity to upgrade to latest-generation computing technology."); Microsoft, Inc., Comments, FERC Docket No. RM26-4-000, at 1 (filed Nov. 21, 2025) ("Microsoft agrees that regulatory frameworks that allow for voluntarily curtailable loads make sense and will be an important tool for accelerating the deployment of critical AI infrastructure . . . a regulatory framework that provides accelerated interconnection processes and clear market signals for curtailable loads should incentivize innovation in datacenter design and operations.").

[105] *See, e.g.*, Monitoring Analytics, LLC*, State of the Market Report for PJM* at 1 (finding that inclusion of existing and projected data center load in the peak load forecast caused a $23.1 billion increase in

State regulators must determine several key parameters to develop an effective BYOC framework:

- What level of capacity procurement is sufficient (e.g., 100% of peak capacity plus reserve margin)? To what extent are such requirements tailored to match the characteristics of a particular large load, including the timing of when supply must be operational?
- To what extent must capacity be “new” to qualify for the framework (or, how to ensure that investments or market participation decisions by existing generation represent truly additional supply, rather than merely shifting constrained supply among customers)?
- What capacity accreditation methods define the capacity requirement?
- What are the consequences of failing to procure the required capacity? How are these consequences enforceable?

In defining these parameters, regulators are likely to seek to balance between ensuring that the capacity procurements required or incentivized by the framework are sufficient to ensure resource adequacy, while also not creating a serious barrier to the economic development that large loads represent. We note that many of the questions that arise in defining an appropriate BYOC requirement are the same as those that must be resolved in defining the class of flexible large load. In either case, a regulator is seeking to define a large load’s level of enforceable commitment to either procure capacity or operate in a way to avoid the necessity of procuring such capacity, ensuring those costs are either borne by the large load or avoided entirely.

Enabling Large Load Flexibility Under Bring-Your-Own-Capacity Frameworks

As with other tools in the state toolkit, the key to ensuring that BYOC frameworks do not deter investment in large load flexibility is ensuring that large loads that meet stringent flexibility commitment requirements are exempt from the BYOC framework, or that the curtailment capability of such commitments counts as eligible capacity pursuant to such a framework. As discussed, an appropriate definition of a flexible large load will entail enforceable commitments that reliably avoid the transmission, distribution, or capacity buildout that would otherwise be needed to serve the large load. As such, qualifying as a flexible large load achieves similar purposes, and warrants its exemption from BYOC requirements or a reduction the amount of capacity it must obtain. Failure to provide a means for flexibility commitments to be valued in BYOC frameworks dilutes the commercial incentive to invest in flexibility, undermining the larger goal of affordably and reliably meeting load growth.

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capacity market revenues in PJM over the last three Base Residual Auctions). These costs are spread across the PJM region, not only to customers in zones experiencing shortages.

Examples of States Currently Engaged in Developing Bring-Your-Own-Capacity Frameworks

Most states that are required to establish or are considering a BYOC framework for large loads remain in the process of developing the implementation details. Examples of states actively considering such frameworks are included here because legislative sessions and regulatory dockets that engage in the challenging questions of how to design such frameworks are likely to provide useful learning opportunities for other decisionmakers.

The Maryland Public Service Commission, for example, is determining the scope of new regulations and tariffs addressing large load interconnection required under the Next Generation Energy Act, adopted by the state legislature in 2025. Under Section 4-212(b) of the Public Utilities Article, the Maryland Public Service Commission must ensure that residential retail electric customers do not bear the financial risks associated with large load customers interconnecting to the grid in Maryland, among other objectives of the law. The Maryland Public Service Commission established a working group and a rulemaking docket through which it will consider and implement any new requirements.[106] Parties in the docket have advocated for the Maryland Public Service Commission to impose a mandatory BYOC obligation on large loads as one step toward ensuring that large loads bear their own costs and do not shift costs to other customer classes.[107] The Maryland Public Service Commission expects to finalize actions to implement the law by September 2026.

Utah enacted SB 132 in 2025, establishing requirements for large load customers[108] and including a framework allowing them to seek an alternative to utility service from qualifying generation providers in cases where the electric utility is unable to timely respond to or resolve requests for service from the large load customer.[109] The Utah Public Service Commission issued a proposed rule to implement SB 132, which remains pending and is not yet final.[110] As implemented under the proposed rule, one aspect of SB 132 would establish a voluntary BYOC framework. Under the proposed framework, a large load customer may opt to be served by a registered large-scale generation provider where it has requested service from the utility, but the utility cannot provide the service within the requested timeframe or the customer and the utility cannot agree upon terms.[111] Once a large load customer elects such alternative service, however, the utility is no longer required to provide that customer

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[106] Maryland Public Service Commission, *Notice Initiating a Rulemaking, Opportunity to Comment and Rulemaking Session*, RM 93 (Dec 9, 2025).

[107] *See* Maryland Office of People's Counsel, Comments, RM 93, at 12 (Jan. 21, 2026).

[108] SB 132 is codified at Utah Code Ann. § 54-26-101 to -901.

[109] *See generally* Utah Code Ann. §§ 54-26-401 & 54-26-501.

[110] State of Utah Public Service Commission, *Notice of Proposed Rulemaking Concerning Utah Code §§ 54-26-101 to 901, Large-Scale Electric Service Requirements*, State of Utah Public Service Commission Docket No. 25-R318-01 (Oct. 31, 2025) (Utah Proposed Rule R746-318)

[111] Utah Code Ann. §§ 54-26-401 (2)(a)(i)(B)-(C)

electric service.[112] Further provisions of the rule would limit the large load customer's ability to rely on generation resources beyond the registered large-scale generation provider, subjecting the load to curtailment if the customer's demand exceeds the real-time dispatch of the contracted large-scale generation providers resources and limiting the duty of the utility to serve that customer, including backup power.[113] Likewise, if a large load customer opts to receive electric service through a "closed private generation system" (i.e., without relying on the utility's system) the utility has no duty to provide that customer any electric service, including ancillary services and backup power.[114] Utah's BYOC framework is thus unique in not only shifting the obligation to procure capacity to the large load customer that elects that option, but in providing new pathways for procurement of supply that do not depend on the electric utility.

CONCLUSION

In the face of growing demand from large load customers, state regulators and utilities face many complex challenges and opportunities. In considering how to enable flexibility commitments, it may be tempting to wait until other states and utilities develop model approaches. But regulatory innovation cannot wait. Without urgent reform, status quo processes will overwhelm planning processes, trigger infrastructure spend that occupies planners and engineers for years, and risk saddling existing customers with unnecessary costs. States that do not innovate will cede economic development opportunities to those that do. Moreover, as FERC contemplates regulating large load interconnection, including a potential future implementation date pursuant to which state-regulated interconnection could transition to federal regulation, states acting prior to that implementation date could shape a significant amount of load that will influence their systems for decades to come. These approaches can lay the groundwork for collaboration with federal regulators, establishing mechanisms for planning and operating the electricity system in a more efficient, reliable manner that draws on the full capabilities of all its customers.

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[112] *Id.* at (2)(a)(i)(E).

[113] Utah Proposed Rule R746-318-402 (2).

[114] Utah Proposed Rule R746-318-601 (2).

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