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Speed to Power: Solutions for Accelerating Large Load Connections

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Executive Summary

Rapid growth in demand from data centers and other large loads is creating a range of new challenges for electricity planners, investors, system operators, and regulators,[1] leading to bottlenecks that have slowed connection[2] of large loads to the electric grid. In response, innovative solutions for accelerating large load connections are beginning to emerge across the U.S.

Drawing on an extensive document and literature review, this report identifies 41 potential solutions for accelerating large load connections, organized into five functional areas that provide a framework for the report.

- *Load forecasting* – Solutions that address increased load forecast uncertainty and the risks associated with utilities underbuilding or overbuilding generation, transmission, and distribution infrastructure.
- *Interconnection* – Solutions that increase the transparency and certainty of distribution and transmission load interconnection processes, improve study efficiency and timing, set incentives to reduce speculative requests, create faster, more flexible kinds of interconnection service, and provide options for interconnection customers to reduce connection times by building their own distribution and transmission facilities.
- *Utility procurement* – Solutions that provide utilities with flexibility to procure equipment in advance of need and procure new resources outside of the normal planning and procurement cycles.
- *Markets and operations* – Solutions that provide greater operational flexibility through changes in real-time energy markets and transmission service, as well as ensure operating reserves are adequate to manage large load demand variability and to fairly allocate the cost of any additional required reserves.
- *Cost allocation and ratemaking* – Solutions that balance cost allocation between large loads and other customers; increase transparency and efficiency through clear rules for how the risks of large load cost impacts will be mitigated; and use wholesale rates, either with the utility continuing to provide retail service, or by allowing large load customers to choose their own generation capacity and energy suppliers through direct access.

Some of these areas, such as interconnection, are more directly related to large load connection, and some are more indirect, such as cost allocation and ratemaking. Indirect solution areas preemptively tackle issues that can lead to bottlenecks. For instance, large load tariffs can be an important strategy for accelerating large load connections if tariff provisions address concerns over economic risks to ratepayers that might otherwise be litigated or investigated in a regulatory proceeding. The 41 solutions are further organized into 13 specific solution areas (Table ES1).

[1] Planners, investors, operators, and regulators are numerous and diverse. Electricity planners and investors include transmission and distribution owners, generation companies, regional system operators, and utility and non-utility load-serving entities. Operators include regional system operators, generation and transmission providers, and other balancing area authorities. Regulators include state and federal electricity regulators.

[2] We use the term 'connection' in this report to capture a broader set of issues in how large loads receive electric service. We use the term 'interconnection' to refer more narrowly to the load interconnection process.

The list of solutions in Table ES1 is not exhaustive. For instance, the report does not address permitting or generator interconnection.[3] Some solutions are applicable only in certain regions; others, such as large load tariffs and wholesale rates, may be mutually exclusive. The solutions range in difficulty and timing, from relatively modest changes that could be implemented in the near term (one to two years), such as streamlined interconnection and large load tariffs, to structural changes that would require a longer runway, such as non-firm transmission service for large loads. The most challenging solutions are those that involve overlapping federal-state jurisdiction, which may need to await the resolution of the Federal Energy Regulatory Commission's proceeding on Interconnection of Large Loads to the Interstate Transmission System.[4] The solutions are not intended to be recommendations or a roadmap, but illustrative examples of potential opportunities available to decision makers.

[3] The report does discuss paired load and generation interconnection processes.

[4] See *Interconnection of Large Loads to the Interstate Transmission System* (Docket No. RM26-4-000), https://www.ferc.gov/rm26-4.

Table ES1. Potential Solutions for Accelerating Large Load Connections

Solution Area	Solutions
Load Forecasting	
S1. Load forecasting approaches	S1.1 Separate load forecasts for large loads S1.2 Regular customer engagement and market research S1.3 New methods for large load forecasting S1.4 Milestone requirements for inclusion in forecasts S1.5 Processes for monitoring project duplication in forecasts S1.6 Forecast reporting requirements
S2. Load forecast coordination	S2.1 RTO* guidelines on large load forecasting S2.2 State involvement in RTO load forecast adjustments S2.3 Data sharing and exchange on large load forecasting
Interconnection	
S3. Load interconnection processes	S3.1 Clear thresholds for large load interconnection S3.2 Disclosure rules for similar interconnection requests S3.3 Coordination between load interconnection and planning processes S3.4 Coordinated interconnection for load and paired generation S3.5 Clear disclosure rules for behind-the-meter generation and storage S3.6 Standard interconnection process elements** S3.7 Cluster studies S3.8 Interconnection data and queue transparency
S4. Fast-track transmission interconnection service	S4.1 Provisional interconnection service S4.2 Surplus interconnection service S4.3 BYOG*** and pay-for-transmission incentives
S5. ERIS**** for loads (transmission)	S5.1 ERIS-like interconnection service for loads
S6. Flexible interconnection (distribution)	S6.1 Staggered connections S6.2 Static flexible interconnection S6.3 Dynamic flexible interconnection
S7. Large load construction of transmission and distribution facilities	S7.1 Option to build
Utility Procurement	
S8. Utility procurement approaches	S8.1 Advance procurement of equipment S8.2 Flexible procurement for new resources
Markets and Operations	
S9. Energy markets and transmission service	S9.1 Load participation in real-time markets S9.2 Non-firm transmission service for loads
S10. Operating reserves	S10.1 Changes in regulation reserve procurement S10.2 Downward contingency reserves S10.3 Changes in reserve cost allocation
Cost Allocation and Ratemaking	
S11. Cost allocation methods	S11.1 Review and update of allocation factors S11.2 Direct assignment of costs
S12. Large load tariffs	S12.1 Clear eligibility requirements S12.2 Standard rates S12.3 Risk mitigation measures S12.4 Interruptible service requirements S12.5 Customer choice programs for large loads
S13. Wholesale rates and access for large loads	S13.1 Wholesale rates under utility service S13.2 Direct access programs

* RTO: regional transmission organization.
** Standard interconnection process elements include discrete process steps, timelines, financial readiness, fees, penalties, decision points, information requirements, milestones, and *pro forma* agreements.
*** BYOG: bring-your-own-generation.
**** ERIS: energy resource interconnection service.

1. Introduction

Rapid growth in large loads — data centers, cryptocurrency mining, fleet electric vehicle (EV) charging, manufacturing, and other industrial loads — is transforming the U.S. electricity industry. Connecting large loads to the grid in a timely and cost-effective manner has presented an array of challenges in planning, interconnection, markets, and ratemaking. However, innovative solutions to these challenges are beginning to emerge, ranging in scale and complexity from utility load forecast improvements to the Southwest Power Pool's (SPP's) high-impact large load interconnection process.

This report describes emerging and potential solutions to connection bottlenecks for large loads, drawing on an extensive review of state regulatory proceedings, parallels between load and generator interconnection, and growing literature on large load interconnection, planning, operations, and cost allocation. The report is organized into three main sections.

- *A Framework for Emerging Challenges and Solutions* – Develops a framework for organizing challenges and solutions to large load connection bottlenecks.
- *Planning, Market, and Regulatory Processes* – Describes the planning, market, and regulatory processes that are involved in connecting large loads, as context for the rest of the report.
- *Emerging and Potential Solutions* – Describes and provides examples of solutions.

The report is a compendium of potential solutions and a reference document, with standalone, cross-referenced sections and extensive citations. Its primary audience is state and federal energy regulators, but it is relevant for a broader audience, including utilities, regional system operators, state policymakers, and consumer advocates.

2. A Framework for Emerging Challenges and Solutions

This section provides a framework for the emerging challenges and solutions to connecting large loads to the grid, including which solution areas are in and out of scope for the report.

2.1 Key Challenges

The challenges for connecting large loads in a timely and cost-efficient manner cut across several different functions in the electricity sector, from load forecasting to ratemaking (see Section 3.1). These challenges include the following areas and questions:

- *Load forecast accuracy and transparency* – How can load-serving entities (LSEs) appropriately manage large load forecast uncertainty, including speculative interconnection requests? How can large load forecasts used in different processes be more transparent?
- *Process coordination* – How can processes for interconnection and planning (resource adequacy, transmission, and distribution) efficiently interact so that planning does not unduly slow interconnection?
- *Interconnection uncertainty* – What is the process through which large loads connect to transmission and distribution systems, how long will the process take, and how much will it cost?

- *Capacity adequacy* – How can large loads begin operation when there is not enough generation, transmission, or distribution capacity available to reliably serve them at all times?
- *Operational impacts* – How can the system reliability issues that may be caused by large loads be efficiently addressed, and what role can large loads play in addressing those issues?
- *Cost shifting and stranded costs* – How can markets and rates be designed to (a) avoid undue cost shifts between large loads and other customers, and (b) avoid stranded costs from large loads that delay taking the full amount of their requested electric service, use less capacity and energy than expected, do not ultimately take service at all, or begin service and then close facilities shortly after?

2.2 Solutions Highlighted in This Report

Regulators, utilities, independent system operators (ISOs),[5] and large loads are beginning to develop a diverse suite of solutions to these challenges. Table 1 shows 41 potential solutions that are highlighted in this report, organized into 13 thematic solution areas and by the functional theme (see Figure 1, Section 3.1) in which the solutions would be implemented. These solutions are not recommendations. They may be suitable for some states or regions but not others, and some of them may be mutually exclusive. Section 4 describes each of the solutions in detail.

[5] We use the term 'ISO' to refer to both independent system operators and regional transmission organizations (RTOs). In cases where we intend to refer specifically to regional transmission organizations, we use 'RTO' rather than 'ISO.'

Table 1. Potential Solutions for Accelerating Large Load Connections

Solution Area	Solutions
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S1. Load forecasting approaches	S1.1 Separate load forecasts for large loads S1.2 Regular customer engagement and market research S1.3 New methods for large load forecasting S1.4 Milestone requirements for inclusion in forecasts S1.5 Processes for monitoring project duplication in forecasts S1.6 Forecast reporting requirements
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* RTO: regional transmission organization
** Standard interconnection process elements include discrete process steps, timelines, financial readiness, fees, penalties, decision points, information requirements, milestones, and *pro forma* agreements.
*** BYOG: bring-your-own generation.
**** ERIS: energy resource interconnection service.

2.3 Out-of-Scope Solutions

The solutions in Table 1 are not exhaustive. Some solutions that could relieve connection bottlenecks for large loads are out of scope for this report. Most prominent among these include the following:

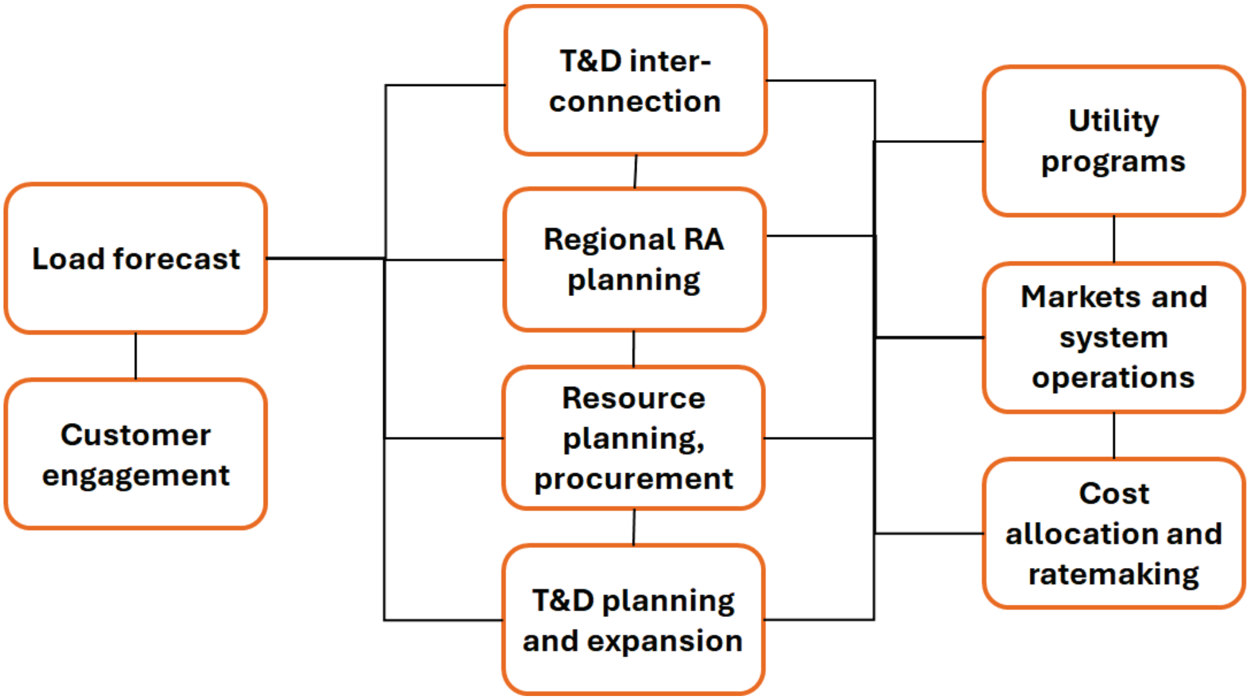
- *Generator interconnection reforms* – In some jurisdictions, the main bottleneck to large load connections may be the generator interconnection process. If, for instance, new generation takes several years to proceed from an interconnection request to commercial operation, the generator interconnection process may be the limiting factor in connecting large loads. DOE's *Transmission Interconnection Roadmap* explores potential solutions for reforming generator interconnection.[6]
- *Large load interconnection standards* – Some of the operational challenges caused by large loads — large, rapid changes in demand, inadvertent disconnection, power quality issues — could be managed through interconnection standards rather than changes in system operations, reducing the need for new reserve or other market products to manage them (see solution area S10, Section 4.4.2). Several recent reports discuss large load operational impacts and the scope for using standards to manage them.[7]
- *Permitting reforms and faster construction timelines* – Permitting for both large loads and generators is often complex, time-consuming, and may unduly slow large load connection. Permitting reform for generation and transmission has been a recent focus of federal legislative efforts.[8] Often the most time-intensive step in large load interconnection is in the interconnection facilities and network upgrade construction phase.[9] At present, there do not appear to be any efforts to more holistically evaluate strategies to reduce construction times.

3. Planning, Market, and Regulatory Processes

Connection bottlenecks for large loads — and solutions to those bottlenecks — involve several interactive planning, market, and regulatory processes: customer engagement, load forecasting, transmission and distribution ((T&D) interconnection for loads and generators, regional resource adequacy (RA) planning, local resource planning and procurement, T&D planning and expansion, utility programs, markets and system operations, and cost allocation and ratemaking (Figure 1).

[6] DOE (2024a). The report does discuss paired load and generation interconnection processes.
[7] EPRI (2025); ESIG (2026a); Quint et al. (2025); NERC (2026).
[8] For background on transmission permitting reforms, see CRS (2025).
[9] For instance, American Transmission Company (ATC) expects that its planning and study process for loads will take 6 to 18 months, whereas any construction requiring line extension will take at least 18 months and potentially as long as 60 months. See ATC (2025).

Figure 1. Planning, Market, and Regulatory Processes Relevant to Large Loads



Customer engagement can improve large load forecast accuracy by enhancing understanding of market trends and customer plans. **Load forecasts**, including forecasts of large load demand, are used in interconnection studies, regional RA planning, LSE resource planning and procurement, and T&D planning. Utilities and some ISOs[10] have formal or *ad hoc* load **interconnection** processes that study whether network upgrades and, in some cases, additional generation capacity will be necessary to connect large loads to transmission and distribution systems. **Regional RA planning** — by ISOs, government agencies, or transmission utilities — evaluates the need for and supports investments in new generation capacity to meet regional RA requirements with growth in large load demand. LSE **resource planning and procurement** secures new generation capacity and energy needed to serve large loads. In **T&D planning**, ISOs and utilities assess whether new transmission or distribution infrastructure will be needed to meet medium-term to longer-term demand growth.

Large loads can participate in **utility programs**, including demand response and other demand-side flexibility programs. They can also contribute to managing system constraints and providing grid services through participation in day-ahead and real-time **markets and operations**. **Cost allocation and ratemaking** determine how the costs and cost savings driven by large loads will be allocated.

The processes in Figure 1 are interrelated. For instance, a wholesale large load that requests non-firm interconnection service may not be included in the load forecast used in RA and transmission planning, would be subject to market and operating rules that allow curtailment during periods of local or system stress, may not be eligible for utility demand response programs, and in exchange for participation could pay non-firm wholesale RA and transmission

[10] We use the term 'ISO' to refer to both independent system operators and regional transmission organizations (RTOs). In cases where we intend to refer specifically to regional transmission organizations, we use 'RTO' rather than 'ISO.'

charges. Understanding these interrelationships is important for developing feasible, effective, and consistent solutions.

3.1 Key Factors Shaping Roles and Responsibilities

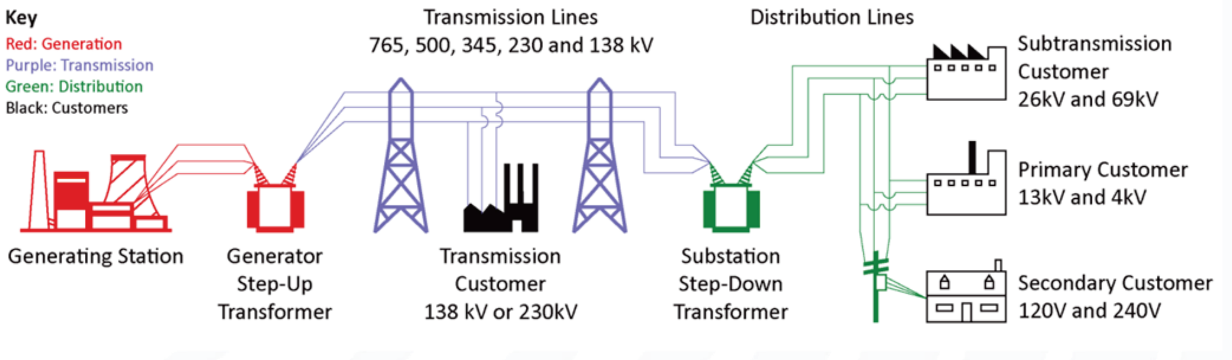
Which organizations manage the processes in Figure 1 and the details of each process depend on regional differences in industry structure (regional and state differences), the voltage at which large loads connect (connection voltages), whether large loads are wholesale or retail customers (market participation), and whether large loads have their own generation and how those generators are configured (generation pairing and configuration). This section describes each of these four factors.

Regional and state differences. The processes in Figure 1 might be managed by one or more organizations — investor-owned utilities, public utilities, rural cooperatives, retail electricity providers, ISOs, generation and transmission providers, federal power marketers, and state agencies — with the details varying by region and state. For instance, a large load connecting to a utility transmission system in California might be supplied by a community choice aggregator, which would need to procure generation capacity on its behalf to comply with an RA program overseen by the California Public Utilities Commission (CPUC). If that load connected to a utility transmission system in Virginia, it would like be supplied by the utility, which could invest in or sign long-term contracts with generation capacity on the load's behalf, or procure capacity in the PJM regional capacity market. This regional diversity can often make it difficult to generalize solutions.

Connection voltages. Large loads may connect to the lower-voltage distribution system, the medium-voltage sub-transmission system, or the high-voltage transmission system, depending on project size, economics, and site and network availability (Figure 2).[11] Each part of the electric grid may be owned and operated by different entities, meaning that the network providers and processes large loads interact with depend on the voltage at which they connect. For instance, a 10-megawatt (MW) load connecting at a distribution voltage in the Midcontinent Independent System Operator (MISO) region would likely need to be studied by the distribution utility and the transmission owner, which may be different entities, and the results of the transmission impact study would need to be coordinated with MISO, which is the transmission provider and reliability coordinator.

[11] Voltage-level boundaries between the distribution system, sub-transmission system, and transmission system are not fixed or consistent across regions or even within the same state. For instance, in California, distribution voltages for the state's three main investor-owned utilities are defined as being below 60 kV (Pacific Gas & Electric), 115 kV (Southern California Edison), and 69 kV (San Diego Gas & Electric). For each utility, facilities that are at or above these thresholds and meet configuration requirements are planned and operated by the California ISO (CPUC 2025a). The Federal Energy Regulatory Commission uses a seven-factor test, established in Order 888 (FERC 1996), to delineate the distribution and transmission on a case-by-case basis when necessary.

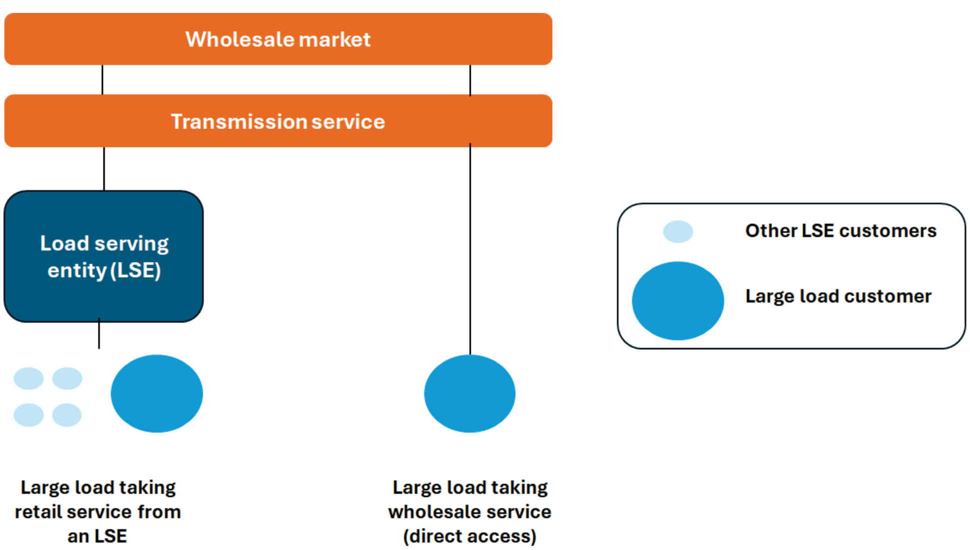
Figure 2. Connection Voltages and Large Loads



Source: NERC (2025).

Market participation. Some states currently have either fully competitive retail sectors or allow limited direct access for larger customers.[12] In states with retail competition, large loads could be (a) wholesale customers, taking transmission service directly under a transmission provider's open access transmission tariff (OATT), or (b) retail customers, taking retail service from a competitive retail provider, a default service utility provider, or a municipal utility or rural electric cooperative, each of which takes transmission service under an OATT (Figure 3). Direct participation in wholesale markets may not correspond to connection voltages; in some states, customers connecting at distribution voltages can also be wholesale customers. Regulated utilities are not responsible for procuring adequate generation resources to supply wholesale customers — wholesale customers supply their own needs — but utilities and ISOs are required to ensure that there is sufficient transmission and distribution capacity to reliably serve them.

Figure 3. Illustration of Large Loads Taking Bundled Retail and Wholesale Service



Notes: This figure does not capture retail ratemaking. In most cases, large loads will be in a large industrial and commercial rate class or in their rate class.

[12] Thirteen states have fully competitive retail sectors. See the Retail Energy Supply Association website (undated, accessed January 2026).

Load-generation pairing and configurations. Large loads may pair with generation and energy storage in a variety of physical and contractual arrangements.[13] These arrangements can have a significant influence on which organization is responsible for interconnection studies, how large loads and generation are studied, and what their capacity impacts and cost obligations will be. This report uses the phrase ‘paired load and generation’ rather than ‘co-located load and generation’ to reflect the fact that generation can be in a different location than load and still influence the capacity needed to serve load. Co-location is thus a subset of load-generation pairing.

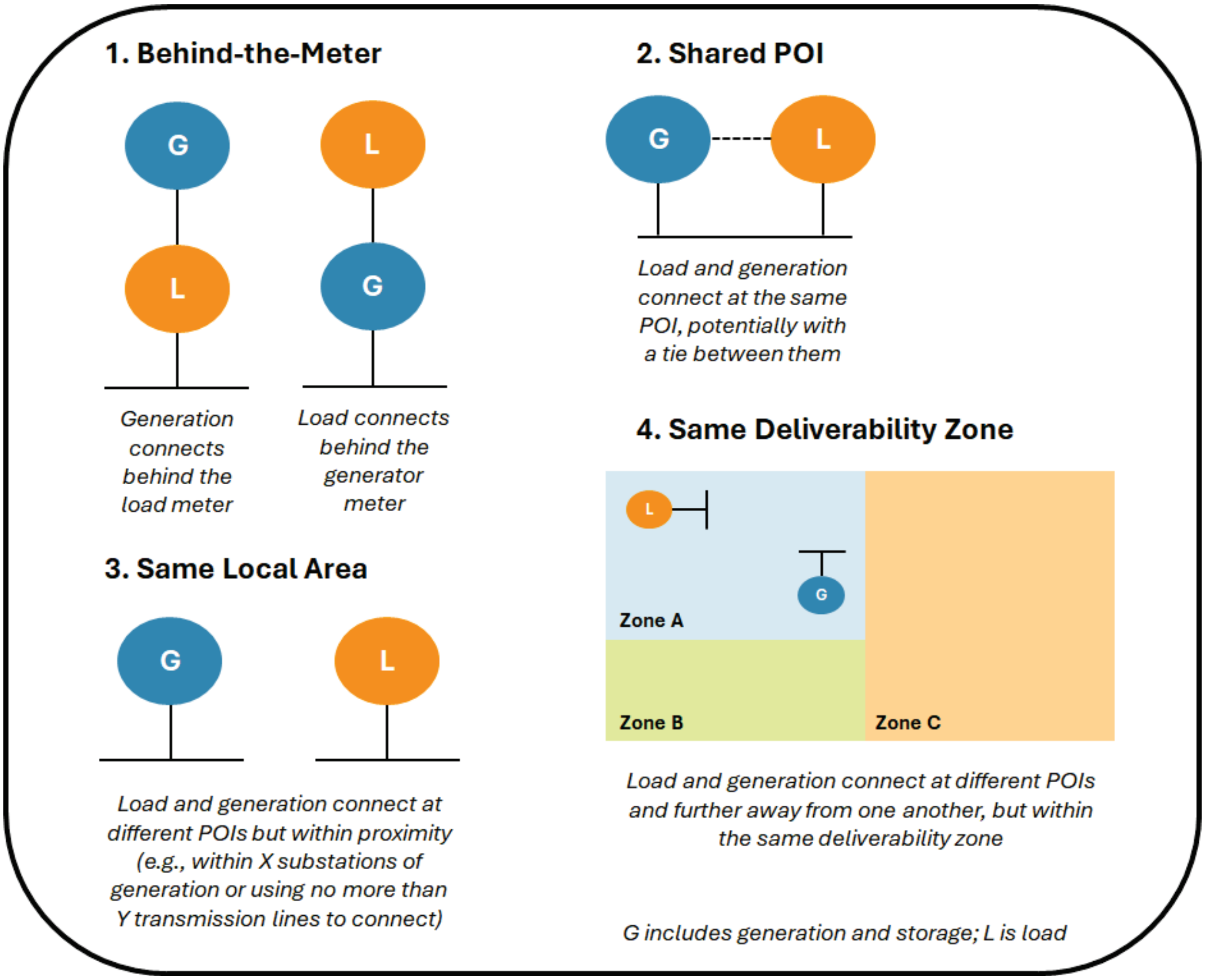
Physical load-generation configurations could include:

1) **Behind-the-meter** generation or load, in which either the generator is connected behind the load meter or the load is connected behind the generator meter.
2) **Shared point of interconnection (POI)**, in which the load and generator share a POI to the transmission or distribution system, potentially with a direct tie between the generator and load.
3) **Same local area**, in which load and generation are located within proximity to one another — measured in terms of physical or electrical distance — but at separate POIs.
4) **Same deliverability zone**, in which load and generation are at separate POIs and farther away from one another but are in the same deliverability zone for RA.[14]

Figure 4 provides a simple illustration of these four configurations. All four configurations can reduce the need for additional transmission and generation infrastructure by limiting net loading on regional transmission systems.[15] If load and generator interconnection studies are coordinated (solution S3.4, Section 4.2.1) and include some limits on operations, all four configurations may allow for faster interconnection (solution area S4, Section 4.2.2). The four configurations have different tradeoffs between interconnection costs and energy resource costs. Configuration 1 likely has the lowest interconnection costs but limits options for energy resources, whereas Configuration 4 provides more options for access to lower cost energy resources but likely has the highest interconnection costs.[16]

[13] To simplify, we use the term ‘load-generation’ rather than ‘load-generation-storage,’ with generation inclusive of paired storage.
[14] Configurations 3 and 4 are based on SPP’s High Impact Large Load Generator Interconnection Assessment (HILLGA) path 2 and 3. For configuration 3 (HILLGA path 2), SPP defined proximate as “using no more than 5 substations, using no more than 2 transmission lines, each load within 2 substations of generation” (SPP 2025a).
[15] Configuration 4 (same deliverability zone) reduces the need for regional transmission infrastructure to deliver power between zones in order to meet RA requirements.
[16] For instance, a data center with behind-the-meter solar and storage might connect at a location with low land costs but lower solar capacity factors than sites farther away. The data center might have lower interconnection costs relative to a solar and storage facility that connects at a different location, but it would have higher energy costs.

Figure 4. Four Configurations for Load Paired with Generation



The four configurations also have different implications for interconnection studies and operations. In cases where load and generation are not at the same POI (configurations 3 and 4), studies treat load and generation as separate entities. In behind-the-meter arrangements and, under some conditions, shared POI arrangements, studies may treat load and generation as a single entity (solution S3.4, Section 4.2.1). In configurations 2 through 4, load and generation typically have separate meters, generators are often required to register as market participants, and system operators have the ability to monitor and dispatch generators and disconnect them, if needed, under emergency conditions. System operators have historically had limited ability to monitor and control behind-the-meter generation, though if larger behind-the-meter generating units become a larger part of a system's energy supply, it may become more important to have this ability (solution S3.5, Section 4.2.1).

3.2 Non-Firm Interconnection, Transmission, and Distribution Service for Large Loads

For the most part, large loads are retail customers, taking service from a utility or other LSE through a contract that, in the case of regulated utilities, is often governed by a retail tariff subject to state regulation (see Section 4.5). When retail load customers connect to the transmission or distribution system, they typically receive firm network service. Firm service means that the transmission or distribution utility studies the new load to determine the amount of generation, transmission, and distribution capacity needed to reliably meet its expected demand during all hours, builds any needed capacity, and then allocates the costs to all customers or to the new load.

Unlike generators, loads have not had access to different kinds or amounts of interconnection service or transmission and distribution service. However, whether explicitly or implicitly, differentiated service levels will likely be an important part of the regulatory framework for non-firm (curtailable) service for large loads. As with generators, service levels for loads may result in different outcomes, depending on market and regulatory contexts. This section describes the current context for interconnection and transmission service levels for generators and what they might imply for loads, as context for several of the solutions.

Interconnection service. Interconnection service refers to the level of service that a generator or load ("interconnection customer") requests when it interconnects. If an interconnection customer requests service at or below its maximum generation or demand level, or in areas with surplus capacity, the customer might be able to connect more quickly or reduce interconnection charges in exchange for some form of curtailable service or for locating at specific points in the transmission or distribution system. How this tradeoff works in practice will depend on the type of interconnection service and the regulatory context.

For the transmission system, the Federal Energy Regulatory Commission (FERC) *pro forma* Large Generator Interconnection Procedures define four kinds of interconnection service:[17]

1) *Network resource interconnection service (NRIS)*, in which the interconnection customer agrees to pay for any necessary network upgrades that would be required for firm transmission service.
2) *Energy resource interconnection service (ERIS)*, in which the interconnection customer agrees to non-firm, "as available" access to the transmission system in exchange for lower interconnection costs and potentially faster interconnection.
3) *Surplus interconnection service*, in which the interconnection customer connects at a transmission substation with surplus interconnection capacity[18] in exchange for faster interconnection and lower interconnection costs.
4) *Provisional interconnection service*, in which the interconnection customer agrees to be curtailed as necessary on a temporary basis until the transmission capacity needed to serve the customer can be built.

These services have historically only been available to generators, though in principle, similar categories could be formally or informally adapted and extended to loads. Creating an ERIS-like service for loads would require different considerations than surplus or provisional service, because ERIS is akin to a curtailable service that could be permanent, whereas surplus interconnection service is not necessarily a curtailable service and provisional interconnection

[17] ERCOT, which is not FERC jurisdictional, does not have these services. For definitions and descriptions of these four services, see FERC (2024a).
[18] Interconnection capacity refers to the amount of injection — or for loads withdrawal — that an interconnection customer is studied for. The premise behind surplus interconnection is that if a generator or load is not using the full amount of capacity that it was studied for, additional generation or load could be added to the point of interconnection up to the capacity that was already studied without the need for more in-depth new study and network upgrades.

service is typically only temporary. This report includes discussion of surplus and provisional service for loads under the “fast track” solutions (solution area S4, Section 4.2.2) and separately an ERIS-like service for loads (solution area S5, Section 4.2.3). As with generation, how these four services would be applied to loads will differ in ISO and non-ISO regions due to differences in transmission rights and operations.

For the distribution system, differentiated levels of interconnection service have potential service types and tradeoffs similar to the transmission system, but because distribution systems are generally subject to state rather than federal regulation, there are no standard procedures to draw from. Non-firm interconnection service for the distribution system is typically referred to as ‘flexible interconnection’ and is usually considered separately from non-firm service on the transmission system. This report maintains that separation (solution area S6, Section 4.2.4).

When large loads are paired with generation, it raises questions about the conditions under which the load and generation should be studied and take service as a single interconnection request versus separate requests. A 300-MW (maximum) load that is connected to the transmission system and has 250 MW of available generation behind its POI may be more inclined to take temporary or longer-term curtailable service if the amount of curtailment is limited to 50 MW rather than 300 MW, but treating the load and generation as a single resource puts other customers at risk if the 250 MW of generation is not available and the customer’s net withdrawal from the transmission system exceeds 50 MW. How to fairly and efficiently address pairing in interconnection service is discussed in solution area S3 (Section 4.2.1).

Transmission and distribution service. Transmission and distribution service refers to the service-level options available to generators or wholesale loads once they interconnect. The difference between interconnection service and transmission or distribution service is subtle and, in some jurisdictions, not meaningful.[19] In principle, however, the costs avoided through non-firm interconnection service are long-run marginal costs, whereas the costs avoided through lower levels of transmission or distribution service may be based on short-run marginal costs.[20]

For the transmission system, the FERC *pro forma* OATT specifies two kinds of transmission service: (1) network integration transmission service (NITS) and (2) firm or non-firm point-to-point (PTP) transmission service.[21] In non-ISO regions, the OATT allows for non-firm PTP transmission service and curtailment of firm and non-firm generation but does not provide a framework for non-firm load service.[22] In ISO regions, most loads are network customers and

[19] For instance, in some non-ISO jurisdictions, generators that request ERIS interconnection are still required to undergo a system impact study when they request transmission service, blurring the line between interconnection and transmission service.
[20] Another way to think about the difference in avoidable costs between interconnection and transmission and distribution service is that, in the former, loads could avoid incremental investments necessary for serving the load or generator, whereas in the latter, the facilities needed to serve the load or generator have already been built, so the avoided costs are short-run costs rather than long-run investment costs. In practice, both interconnection and transmission service are often “priced” in terms of long-run marginal or embedded costs rather than short-run marginal costs.
[21] NITS is a firm service that allows a transmission customer to dispatch its resources within the transmission network in a manner comparable to the transmission provider's, without specifying points of delivery. PTP can be firm or non-firm and requires the transmission customer to specify points of delivery. For more on these services, see FERC (2022).
[22] In non-ISO regions, large load customers taking NITS or PTP service would be required to designate resources with which they plan to serve their loads (for NITS potentially relying on the utility) and

pay for firm transmission service, though loads can bid flexibility in day-ahead markets and through demand response products. Neither the non-ISO nor the ISO regions have a well-defined non-firm load service for the transmission system. However, in December 2025 FERC directed PJM to develop a non-firm service for co-located large loads.[23] The changes required to introduce non-firm service for loads would be different in ISO and non-ISO regions, as discussed in solution area S9 (Section 4.4.1).

Distribution systems generally do not have differentiated service levels or open access requirements. All customers that use distribution systems are effectively network customers and pay rolled-in distribution charges. A curtailable load service for distribution systems would be different than traditional demand response because it would (a) allow distribution operators to curtail net loads to relieve distribution constraints and (b) require distribution planners to adjust the load forecasts used in planning. This service might be complementary to flexible interconnection, as choosing flexible interconnection implies that an interconnection customer will take curtailable service. However, curtailable service might also be extended to existing customers rather than being limited to new interconnection requests.

4. Emerging and Potential Solutions

We group the solutions in this section into five functional areas: load forecasting, interconnection, resource planning and procurement, markets and operations, and cost allocation.[24]

4.1 Load Forecasting

Large loads are increasing load forecast uncertainty and raising the risk that utilities will underbuild or overbuild generation, transmission, and distribution infrastructure.[25] Load forecasting solutions aim to reduce these risks by increasing large load forecast transparency, accuracy, and accountability (solution area S1, Section 4.1.1), and increasing coordination between RTOs/ISOs and LSEs and other forecast providers on the load forecasts used in planning for RA and transmission (solution area S2, Section 4.1.2).

Table 2. Load Forecasting Solution Areas

Solution Area
S1. Load forecasting approaches
S2. Load forecast coordination

schedule generation and loads through the transmission provider. The OATT stipulates that if those schedules are not physically feasible, for instance due to congestion, the transmission provider will curtail the generation schedule according to transmission service-level priority, but the OATT assumes that the transmission provider would continue to provide power to the load, only curtailing the load in system emergencies. Although the OATT allows for schedule curtailment and non-firm transmission service; it does not equate to a curtailable service for loads. Schatzki et al. (2024) note that FERC does not require behind-the-generator-meter loads to designate as network loads, which does create some ambiguity in the “firmness” of load requirements under the OATT.

[23] FERC directed PJM to require eligible customers, such as utilities, that are taking transmission service on behalf of co-located loads to take one of three transmission services: (1) network integration transmission service, (2) a new firm contract demand service, or (3) a new non-firm contract demand service (FERC 2025a). As of the time of writing, PJM had not yet submitted its compliance filing.

[24] The solutions in this paper were last updated in February 2026.

[25] ESIG (2025).

4.1.1 Load Forecasting Approaches (Solution Area S1)

Large load forecasting presents new management, methodological, and regulatory challenges for forecasters and regulators. The size of potential forecast errors is much larger now than over the past four decades, raising the stakes of forecast accuracy and suggesting a stronger role for regulators in overseeing load forecasts.[26] Balancing reliability and cost risks of under- and over-forecasting varies across jurisdictions. Some jurisdictions may be willing to accept more reliability risk in exchange for lower costs, whereas others may be willing to pay more to reduce reliability risks.[27]

The solutions in S1 (Table 3) seek to increase large load forecast transparency, develop new approaches to manage forecast uncertainty, and increase accountability for forecast accuracy.

Table 3. Potential Solutions for Load Forecasting Approaches (Solution Area S1)

• S1.1 Separate load forecasts for large loads • S1.2 Regular customer engagement and market research • S1.3 New methods for large load forecasting • S1.4 Milestone requirements for inclusion in forecasts • S1.5 Processes for monitoring project duplication in forecasts • S1.6 Forecast reporting requirements

S1.1 Separate load forecasts for large loads. Load forecasters can develop and use separate, parallel processes for forecasting conventional load and some types of large load customers, using customized forecasting methods and reporting results separately. Separating the large load forecast can improve transparency and clarify opportunities for forecast improvements. It can also help planners to better understand and characterize forecast uncertainty. Many utilities currently create separate load forecasts for data centers, including Dominion Energy Virginia, Georgia Power, Arizona Public Service, and Santee Cooper.[28] Separate large load forecasts should be coordinated with regression-based overall load forecasts to avoid double counting.

S1.2 Regular customer engagement and market research. Many LSEs have customer account managers for their large commercial and industrial customers, though customer

[26] The magnitude of today's large load-driven forecast errors may be less than forecast errors in the 1970s. At the most erroneous point in the "NERC fan" (Nelson et al. 1989), U.S. LSEs over-forecasted sales over a five-year period by around 700 terawatt hours (~130 gigawatts of peak demand assuming an average system load factor of 0.6). By contrast, in 2025 load forecasters forecasted U.S.-wide 2030 summer peak demand to increase by 166 gigawatts (Wilson et al. 2025). Even if current load forecasts are overly optimistic by 50%, load forecast errors would be smaller than they were in the 1970s.

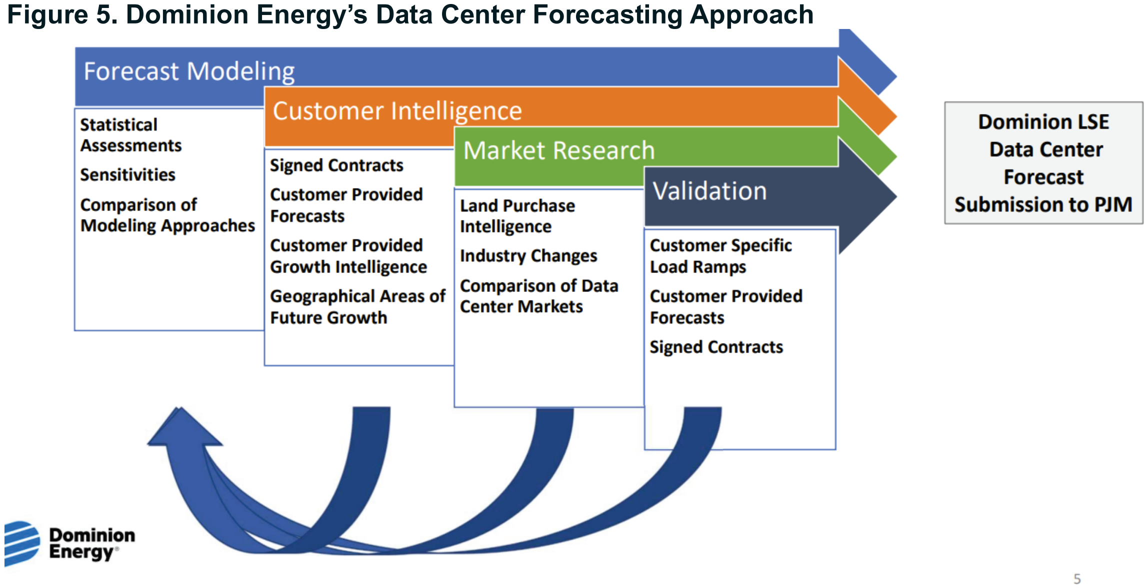
[27] In general, regulated utilities have historically over-forecasted load, ostensibly in part because the political and economic cost of having excess capacity is lower than the cost of having insufficient capacity. Following overly aggressive load forecasts in the 1970s and cost disallowances in the 1980s, LSEs began a series of downward adjustments to load forecasts (the NERC fan) that brought forecasts more in line with actual demand (Nelson et al. 1989). LSE load forecasts began to rise again in the late 1980s (Hudson 1993) and by the 2000s over-forecasts were again the norm as sales continued to slow in the 2000s and then flatten after the 2007-2009 recession (Carvallo et al. 2016; Sward et al. 2025; Kahrl 2021). Over-forecasting may be justified, particularly in times of supply constraints and when demand is policy-driven (Tsuchida et al. 2024), but U.S. experience in the 1970s, as well as with data center loads in the early 2000s (Shehabi et al. 2016), suggests that caution and balance is warranted.

[28] ESIG (2025).

relations departments may be limited in their ability to generate information for large load forecasts due to limits in staff, expertise, or remit. Enhancements to customer relations that could improve load forecasts include: (a) more regular engagement with large load customers to understand the magnitude and location of expected customer growth and changes in expectations; (b) reporting requirements for large load customers; (c) internal processes and coordination to ensure that information gained through customer engagement is shared with load forecasting departments and incorporated in load forecasts; and (d) market research on large load industry trends and growth indicators like permitting and land acquisition.

LSEs will need to balance the level of effort in these areas with cost and expected improvements in load forecast. For LSEs with larger amounts of expected large load growth, more effort might be justified. Dominion Energy provides an example of a more comprehensive approach to customer engagement and market research. Its data center forecasting process includes forecast modeling, customer intelligence, market research, and validation (Figure 5).

Figure 5. Dominion Energy's Data Center Forecasting Approach



Source: Blackwell (2025).

S1.3 New methods for large load forecasting. New methods could address three key forecasting challenges associated with large loads: nearer-term uncertainty, longer-term uncertainty, and lack of historical data. Nearer-term sources of uncertainty include customer project completion rates, in-service dates, project ramp-up rates, locations, customers' actual peak demand and load factors, and the extent to which customers rely on their own generation versus system generation.[29] Longer-term sources of large load-specific forecast uncertainty include policy and economic drivers, technological change, electricity prices and price response, and customer consumption patterns and load flexibility. LSEs often have limited historical data on these variables to parameterize forecast models.[30]

[29] These performance characteristics can vary significantly across large load types. For instance, data centers may take years to get to full capacity, whereas cryptocurrency miners can ramp up demand, relocate, and cease operations quickly (Sherwood 2025).
[30] ESIG (2025).

Methods for managing forecast uncertainty include scenarios and probabilistic methods. Scenarios could incorporate one or more of the sources of uncertainty listed above. Probabilistic forecasting methods could be based on probability weightings for specific variables or more complex Monte Carlo simulation that considers a broad range of factors.

Adaptive approaches to forecasting and decision-making, in which forecasts are regularly updated based on new information, can help to manage both nearer-term and longer-term forecast uncertainty and deal with the lack of historical data.[31] Adaptive forecasting requires an understanding of key uncertain variables, a process to regularly collect and update information on those variables, a level of meaningful disaggregation of customer types to capture diversity in those variables, and avenues to incorporate updated forecasts into decision-making.

One of the most important lessons of the U.S. electricity industry's experience with over-forecasting in the 1970s was the influence of prices on demand.[32] Price response is usually incorporated into load forecasting through price elasticities. However, the nearer- and longer-term price responsiveness of data centers, cryptocurrency miners, EV fleet chargers, and other large loads is not well understood. Better incorporating the uncertainty associated with large loads' price response into load forecasting is an area of ongoing need.

Probabilistic load forecasting
Santee Cooper began using probabilistic forecasts for large loads its 2023 integrated resource plan (IRP). The following excerpt from Santee Cooper's 2025 IRP (Santee Cooper 2025) describes its forecasting process:

"Accommodating uncertainty surrounding the probability a project will be sited in Santee Cooper or Central member cooperative service territory, the magnitude of such potential projects, and the timing and potential delays of such projects, Santee Cooper's stochastic approach evaluated 24 potential customers ranging in size from 2 MW to 500 MW. Like in the load forecast used in the 2024 IRP Update, after evaluating the results of 50,000 trials, Santee Cooper chose to include the 50th percentile outcome in its load forecast. Since the 2024 load forecast, several large potential loads signed contracts in Santee Cooper or Central member cooperative service territory, necessitating their removal from the stochastic model and their inclusion in the conventional load forecast. Thus, the stochastic results for the 2025 Load Forecast are lower than the forecast used in the 2024 IRP Update by about 220 MW; however, this is the result of load becoming more certain and thus being removed from the risk-adjusted post modeling adjustment and being included in the standard modeling."

S1.4 Milestone requirements for inclusion in forecasts. Load forecasters must determine at what point in the large load project cycle — from inquiry to service request to service agreement — large loads will be included in the load forecasts used for investment decision-making. Inclusion later in the project cycle provides greater certainty, while inclusion earlier provides more flexibility and runway to build new infrastructure. Finding the right balance requires judgment and as a result may invite scrutiny from regulators and stakeholders.[33]

[31] See Bessasparis et al. (2025) for a more detailed description of adaptive approaches to forecasting.
[32] Nelson et al. (1989).
[33] This solution is a subset of the previous one on forecasting methods. A milestone-based approach to inclusion in forecasts can be a form of probability weighting, as in the California example showed in this section. We included milestone requirements as a separate solution due to their importance.

Milestone-based approaches to determining inclusion can provide transparent benchmarks. These approaches can consider multiple milestones. For instance, a forecast might include all large loads with an executed electric service agreement and then a smaller fraction of expected load from projects that have completed studies or have requested service (see California example in box). A growing number of states and utilities are moving toward explicit rules that only allow large loads to be included in load forecasts once customers have a service agreement, to reduce the risk of stranded cost due to withdrawn projects.

Load forecast milestone examples

Milestone requirements for transmission and RA planning in Texas
Texas' *Substantive Rules Applicable to Electric Service Providers* (§25.370 ERCOT Large Load Forecasting Criteria) do not allow distribution service providers or the Electric Reliability Council of Texas (ERCOT) to "… include a large load customer's forecasted demand in a load forecast used for identifying transmission planning needs or performing resource adequacy assessments unless the large load customer executed an interconnection agreement… and provided all of the disclosures and financial commitments required for such an agreement…"

Milestone-based confidence levels for system and local planning in California
The California Energy Commission (CEC) is responsible for aggregating LSE load forecasts into forecasts used in statewide integrated resource planning, RA planning, and California ISO (CAISO) transmission planning. For its 2025 forecast (CEC 2025), the CEC proposed three confidence levels (low, mid, and high) to weight data center load forecasts, with progressively more weight given to loads that had already signed an electric service agreement (see table below). The mid forecasts were used in system planning studies, whereas the high forecasts were used in local planning studies.[34]

Group	Confidence Level		
	Low	Mid	High
Group 1. Signed agreement for electric service	50%	70%	100%
Group 2. Active application for electric service	-	33%	50%
Group 3. Inquiries	-	-	10%

Milestone requirements for load forecasts used in procurement in Colorado
The Colorado Public Utilities Commission's decision approving Xcel Energy's 2024 Just Transition Solicitation (Colorado PUC 2025) specifies that "…to be included in the load forecast, large customers must execute both an IA [interconnection agreement] and an ESA [electric service agreement]." The forecast will be used to determine how much new generation capacity and energy Xcel will need to procure through its resource solicitation.

PJM's milestone-based approach to load forecast adjustments
PJM adjusts the load forecasts submitted by electric distribution companies and LSEs to determine the final load forecasts that it uses in transmission and RA planning. In 2025, PJM began to use a milestone-based approach to adjust large load forecasts (PJM 2025a). Large loads expected to come online in three years or less that have a construction commitment or electric service obligation will be included in the PJM load forecast. For large loads expected to come online within three to eight years, forecaster submissions need to either (a)

[34] See p. 28 of CEC (2026) for more on how the different forecasts are used in planning.

demonstrate milestone achievements and how these milestones relate to the probability of the project coming online or (b) accept a 50% derate in the large load forecast.

Milestones are most useful when point-estimate load forecasts are used for investment decision making. An alternative to using point-estimate forecasts in decision making would be to adopt scenario-based or probabilistic decision-making methods, such as least-regrets and robust decision-making methods.[35]

S1.5 Processes for monitoring project duplication in forecasts. Customers may make multiple service inquiries or interconnection requests for the same project, either to the same utility or to multiple utilities. This can lead to inflated forecasts and overbuilt infrastructure in one region to serve customers that choose to locate in another region. A growing number of legislatures, regulators, and utilities are creating disclosure rules, requirements on load forecasters, and communications strategies with customers to determine whether large load projects are duplicative.[36] If utilities are aware of duplicative projects, they can be discounted or otherwise managed in the load forecast. However, it is often difficult to determine if projects are duplicative.

Disclosure requirement examples

SB6 "substantially similar" disclosure requirements in Texas
SB6 stipulates that qualifying (≥ 75 MW) loads must report to the interconnecting utility any "substantially similar" interconnection requests that would result in the customer "materially changing, delaying, or withdrawing the interconnection request," subject to confidentiality concerns and disclosure rules.

Disclosure requests on load forecasters in PJM
In 2026, PJM will amend its load adjustment process to require transmission owners to ask their customers if load interconnection requests are duplicative and report that information to PJM (PJM 2026).

Santee Cooper's requests for disclosures of alternative sites
Santee Cooper asks customers whether they are considering alternative sites and incorporates the data into the project realization scoring used in its forecasting (ESIG 2025).

S1.6 Forecast reporting requirements. Reporting requirements for large load forecasts can help to improve coordination and accountability. Several jurisdictions require, or are beginning to require, more reporting on large load forecasting (and interconnection). Some public utility commissions (PUCs) require utilities to file regular reports on large load forecasts or on large load trends more broadly. In some restructured states, legislatures have proposed requiring PUCs to review, coordinate, validate, or report on load forecast information from utilities. Reporting requirements can be reviewed and improved to ensure that load forecasts can be

[35] The importance of, and methods for, addressing decision making under uncertainty are by no means new to the U.S. electricity industry (Hirst and Schweitzer 1990; Hobbs 1995). However, the application of tools for managing uncertainty has varied significantly across jurisdictions (see Kahrl et al. [2016] for IRP examples) and there are still differences in interpretation in how different methods should be applied (see Pfeifenberger [2025] for a discussion related to transmission planning). For more on methodological issues in the use of scenarios and sensitivities in IRP see Biewald et al. (2024).
[36] Disclosure requirements are often implemented through interconnection and are discussed in S3.2 (Section 4.2.1) as well.

compared with actual data to validate and improve future large load forecasting models and methods.[37]

Utility reporting requirement examples

- Entergy Arkansas must file annual reports regarding its Large Power High Load Density Service.
- The North Carolina Utilities Commission required Duke Energy to file semiannual reports on large loads addressing changes to the proposed large electric load additions in the advanced stage of development.
- The Georgia PSC required Georgia Power to continue providing quarterly large load economic development reports and include additional information.

PUC reporting requirement examples

- The General Assembly of Pennsylvania's proposed Load Forecast Accountability Act would require the Pennsylvania PUC to "review and validate load forecasts submitted by Pennsylvania utilities to PJM; coordinate with PJM and other states so that system planning reflects accurate, nonduplicative information; and obtain access to materials, including confidential agreements, that are necessary to perform this oversight."
- The New Jersey Legislature's proposed Load Forecast Accountability Act would require utilities to provide load forecast information to the Board of Public Utilities (BPU), BPU to coordinate with PJM to ensure that PJM incorporates load forecast information in a "fair, accurate, and non-duplicative manner," and BPU to report annually to the governor and legislature.

4.1.2 Load Forecast Coordination (Solution Area S2)

In most RTOs, LSEs or distribution utilities ("RTO members") are responsible for the load forecasts used in procurement and planning.[38] RTOs assemble these local forecasts from their members, in some cases with adjustments, into a regionwide forecast used to plan regional RA and transmission. Local and regional forecasts require coordination to ensure that they reflect consistent expectations. The solutions in S2 (Table 4) ensure more consistency in the local load forecasts used to develop regional forecasts (S2.1), enable more state review in RTO forecast adjustments (S2.2), and strengthen data sharing and exchange between RTOs and their members (S2.3).[39]

Table 4. Potential Solutions for Load Forecast Coordination (Solution Area S2)

- S2.1 RTO guidelines on large load forecasting
- S2.2 State involvement in RTO load forecast adjustments
- S2.3 Data sharing and exchange on large load forecasting

[37] ESIG (2025).
[38] This solution area focuses on multistate RTOs rather than state-specific ISOs. Some of the solutions may be applicable in the latter, but in general, load forecasting in state-specific ISOs is different than in RTOs. In California, the CEC is responsible for assembling a statewide load forecast based on load forecasts from utilities (CAISO 2025). New York ISO is responsible for load forecasting in New York (NYISO 2025a). ERCOT is responsible for load forecasting in Texas, with large load forecasts provided by transmission service providers (see https://www.ercot.com/gridinfo/load/forecast for more on load forecasting in ERCOT).
[39] FERC has expressed interest in improving the coordination required for RTO large load forecasting (FERC 2025b).

S2.1 RTO guidelines on large load forecasting. RTOs' RA and transmission planning relies on load forecasts from tens to hundreds of RTO members in multiple states, each of which may use different methods, terminology, and definitions. As a result, two large load forecasts with the same demand may reflect different expectations and levels of certainty. Additionally, some RTOs use their own forecasts, rather than aggregated member forecasts, for longer-term transmission planning. RTOs do not have access to the same customer information that their members have, which makes it difficult to interpret and harmonize member-supplied load forecasts and develop longer-term forecasts.[40]

Some RTOs have guidelines for member load forecasting but do not provide specific guidelines on large load forecasting.[41] Specific guidelines for large load forecasting could help to improve transparency, consistency, and accuracy, but they will need to balance standardization and local flexibility. As a starting point, however, greater consistency in terminology, classifications, and ways that regional forecast methods relate to LSE forecast methods could improve understanding and quality of large load forecasts.[42]

S2.2 State involvement in RTO load forecast adjustments. In regions where RTOs adjust load forecasts submitted by members, such as in PJM, state agencies may wish to review such adjustments. State agency review of adjusted forecasts can improve transparency and buy-in for the results. PJM implemented changes to its load forecasting process in January 2026 that allow state PUCs to review and provide feedback on large load adjustments before the PJM load forecast is finalized.[43]

S2.3 Data sharing and exchange on large load forecasting. To help bridge the large load information asymmetry between RTOs and their members, RTOs could request more information on large loads from members. MISO's voluntary Long-Term Load Forecast Pilot Survey, released in September 2025, is an example of such efforts.[44] RTOs could also help to support more public information on customer data and forecasting best practices through presentations at committee meetings.[45]

4.2 Interconnection

Interconnection solutions include those that increase the transparency and certainty of distribution and transmission load interconnection processes (solution area S3), improve study efficiency and timing (S3, S4, S5, S6), set incentives to reduce speculative requests (S3), create

[40] For instance, a utility in one state may only include large loads in its forecast if customers have a service agreement and may exclude duplicative projects based on customer surveys, while a utility in another state may include early-stage large load projects in its forecast and make no adjustments for duplicative projects. The RTO may use different assumptions for its long-term load forecast than either of these utilities. See PJM (2025b) for a description of harmonization challenges in practice.

[41] For instance, MISO's *Peak Forecasting Methodology Review* (MISO undated) provides a list of acceptable forecast methods, and MISO requires documentation of methods and conducts regular reviews of member forecasts (MISO 2024). Southwest Power Pool (SPP)'s Large Load Task Force will "develop best practice guidelines and recommendations to improve load forecasts utilized by SPP" (SPP 2025b, p. 6).

[42] ESIG (2025).

[43] PJM (2026).

[44] See MISO (2025) for more detail.

[45] See, for example, PJM's proposal in its response to FERC's letter on large load forecasting (PJM 2025b).

faster, more flexible kinds of interconnection service (S4, S5, S6), and provide options for interconnection customers to reduce connection times by building their own distribution and transmission facilities (S7).

Table 5. Interconnection Solution Areas

Solution Area
S3. Streamlined, transparent large load interconnection processes
S4. Fast-track transmission interconnection service
S5. ERIS for loads (transmission)
S6. Flexible interconnection (distribution)
S7. Self-funded network upgrades

Load size, connection voltage, and load-generation arrangements determine which entities will need to study new service requests (see Section 3.1). In many cases, large load requests to connect to the transmission system will be studied by transmission owners, requests to connect to the distribution system will be studied by distribution owners, and requests to connect paired generation and load to the transmission system may be studied separately or, in some regions, by the transmission provider responsible for generator interconnection. However, the entity that conducts interconnection studies may be different from the one that sets interconnection procedures and rules, manages the interconnection process, and administers an interconnection tariff. For instance, transmission owners would likely still be responsible for interconnection studies within the context of an ISO large load interconnection tariff.

In principle, wholesale loads could be subject to a FERC-jurisdictional interconnection tariff, but FERC has thus far declined to create standard interconnection procedures and agreements for loads. A federally regulated load interconnection tariff could allow for rapid implementation of some types of solutions in this section, though it would need to find balanced approaches to situations with jurisdictional overlap, such as when a large load taking wholesale service connects to the distribution system, or when a large load taking retail service through a state-regulated utility connects to the transmission system. Most of the solutions in this section do not require federal interconnection rules and may be applicable to distribution systems.

4.2.1 Load Interconnection Processes (Solution Area S3)

Across transmission providers and distribution utilities, interconnection processes for large loads range from more streamlined and transparent to more *ad hoc* and unstructured. Where they do not already exist, implementing more formal, streamlined, and transparent large load interconnection processes could help to reduce speculative interconnection requests, provide greater process clarity and cost certainty, and accelerate interconnection timelines. The solutions in S3 (Table 6) all aim to streamline, increase transparency, and align incentives in interconnection processes. The report discusses load flexibility in interconnection in solution areas S4, S5, and S6 (Sections 4.2.2, 4.2.3, and 4.2.4, respectively).

Table 6. Potential Solutions for Load Interconnection Processes (Solution Area S3)

- S3.1 Clear thresholds for large load interconnection
- S3.2 Disclosure rules for similar interconnection requests
- S3.3 Coordination between load interconnection and planning processes
- S3.4 Coordinated interconnection for load and paired generation
- S3.5 Clear disclosure rules for behind-the-meter generation and storage
- S3.6 Standard interconnection process elements
- S3.7 Cluster studies

- S3.8 Interconnection data and queue transparency

S3.1 Clear thresholds for large load interconnection. Depending on load size, connection voltage, and location, connecting loads may or may not need a system impact study or may be able to be studied for local rather than regional impacts. Utilities and ISOs can specify when loads will need to proceed through a large load interconnection process, with more detailed impact studies, by setting size (peak MW) and connection voltage thresholds for large load interconnection. Table 7 provides examples of large load thresholds for ISOs and utilities. In principle, these thresholds should be determined using studies or engineering judgment about the size, voltage, and location at which large loads begin to have more significant system impacts.

Table 7. Example Size and Voltage Thresholds for Large Load Interconnection

ISO or Utility	Peak Demand and Connection Voltage Thresholds
NYISO	> 10 MW at ≥ 115 kV ≥ 80 MW at < 115 kV
SPP	≥ 50 MW at > 69 kV ≥ 10 MW at ≤ 69 kV
ERCOT and utilities	≥ 75 MW
Portland General Electric (PGE)	≥ 1 MW
Sunflower Electric Power Corporation	≥ 25 MW

Notes and sources: At the time of writing, only three ISOs (ERCOT, NYISO, SPP) had large load interconnection processes. For NYISO's and SPP's thresholds, see NYISO (2025b) and FERC (2026). For others, see the ERCOT, PGE, and Sunflower large load interconnection websites.

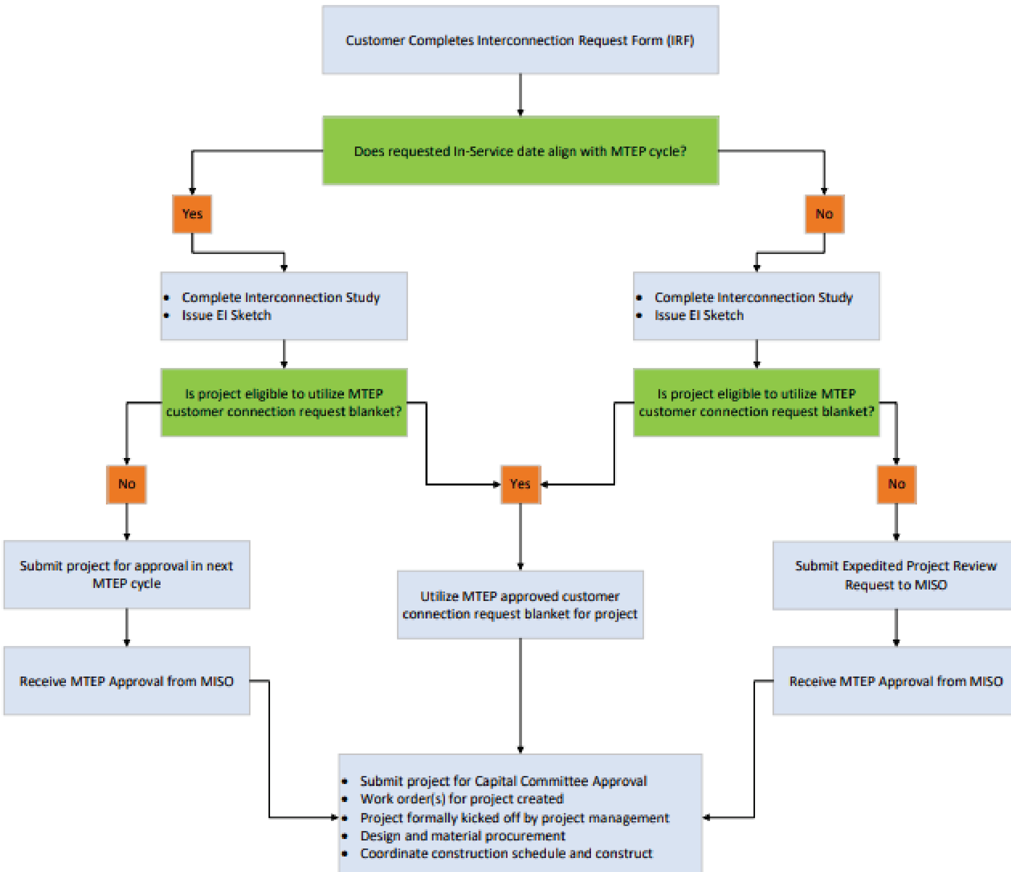
S3.2 Disclosure rules for similar interconnection requests. In principle, disclosure rules for similar interconnection requests could help to better manage the uncertainty created by speculative requests. For instance, Texas' SB6 requires qualifying (≥ 75 MW) loads to report to the interconnecting utility any "substantially similar" interconnection requests that would result in the customer "materially changing, delaying, or withdrawing the interconnection request," subject to confidentiality concerns and disclosure rules.[46] In 2026, PJM will amend its load adjustment process to require transmission owners to ask their customers if load interconnection requests are duplicative and report that information to PJM.[47] As discussed in solution area S1, information about duplicative interconnection requests could be used to inform load forecasts. There is little, if any, information on how this disclosing duplicative interconnection requests could inform or improve interconnection processes.

S3.3 Coordination between load interconnection and planning processes. Load interconnection is often part of a complex arrangement of study processes that involve different studies and may involve multiple organizations. For instance, a 10-MW load connecting at distribution voltage may need to be studied by a distribution utility, a separate transmission utility,[48] and an ISO. The ISO study might be part of an interconnection process or part of the

[46] Texas Legislature (2025).
[47] PJM (2026).
[48] In some cases, the distribution and transmission utility will be the same; in others, they may be different. For instance, many investor-owned utilities are distribution and transmission owners, but they also provide transmission service to distribution-owning municipal utilities and cooperatives that are located within their service territories. A data center connecting to a municipal utility's distribution system would need to be studied by the municipal utility for distribution system impacts and by the transmission

ISO's transmission planning and RA planning process. To provide more visibility to customers, utilities and ISOs can document which organizations will conduct what studies, which organization will manage the study process, and how interconnection will be coordinated with transmission planning and RA planning, if necessary. For example, Figure 6 shows International Transmission Company's (ITC) illustration for how it coordinates load interconnection with MISO Transmission Expansion Planning (MTEP).[49]

Figure 6. ITC's Illustration of Coordination Between its Load Interconnection Process and MTEP



Source: ITC's customer connections website.

S3.4 Coordinated interconnection for load and paired generation. In cases where large loads have paired generation, the generation interconnection process may be separate from the load interconnection process and managed by different organizations. Separate processes can be inefficient, particularly when generation is behind the same POI or the same meter as the

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utility for transmission system impacts. In some states, such as Michigan and Wisconsin, transmission and distribution ownership is largely by different utilities.

[49] In MISO, transmission owners are responsible for studying and mitigating the system impacts of large load interconnection requests. Transmission owners then submit both the requested load amount (MW peak) and any network upgrades needed to reliably serve the load to MISO through the annual MTEP process. If the load connects, the load will be included in future MISO load forecasts used in system planning studies. LSEs, and not necessarily transmission owners if they are different organizations, are responsible for including large loads in the load forecasts that they submit to MISO. If load interconnection requests miss the window for MTEP study, they can be studied in an expedited review process. For more on MISO's load interconnection process, see MISO (2023).

load. For instance, a 20-MW load with 5 MW of distributed photovoltaics (PV) and 5 MW of battery storage requesting transmission interconnection may need to have its 20 MW of load studied by a transmission utility through a load interconnection process and its 10 MW of PV and batteries studied by an ISO through the small generator interconnection process. These studies could have different timelines and lead to unnecessary network upgrades and upgrade costs if both the load and generation are studied at their maximum MW withdrawal and injection amounts.
Basic coordination between load and generator interconnection might simply consist of making sure that different organizations or departments within a utility are aware of load and generation requests, which might help to better align timelines and study assumptions. A more integrated approach would be to study load and generation requests as a single interconnection request, though this implies that the same organization is responsible for both.[50] SPP's High Impact Large Load Generator Interconnection Assessment (HILLGA) process, approved by FERC in January 2026, is an example of an interconnection process in which load and generation are studied in a single request.[51]

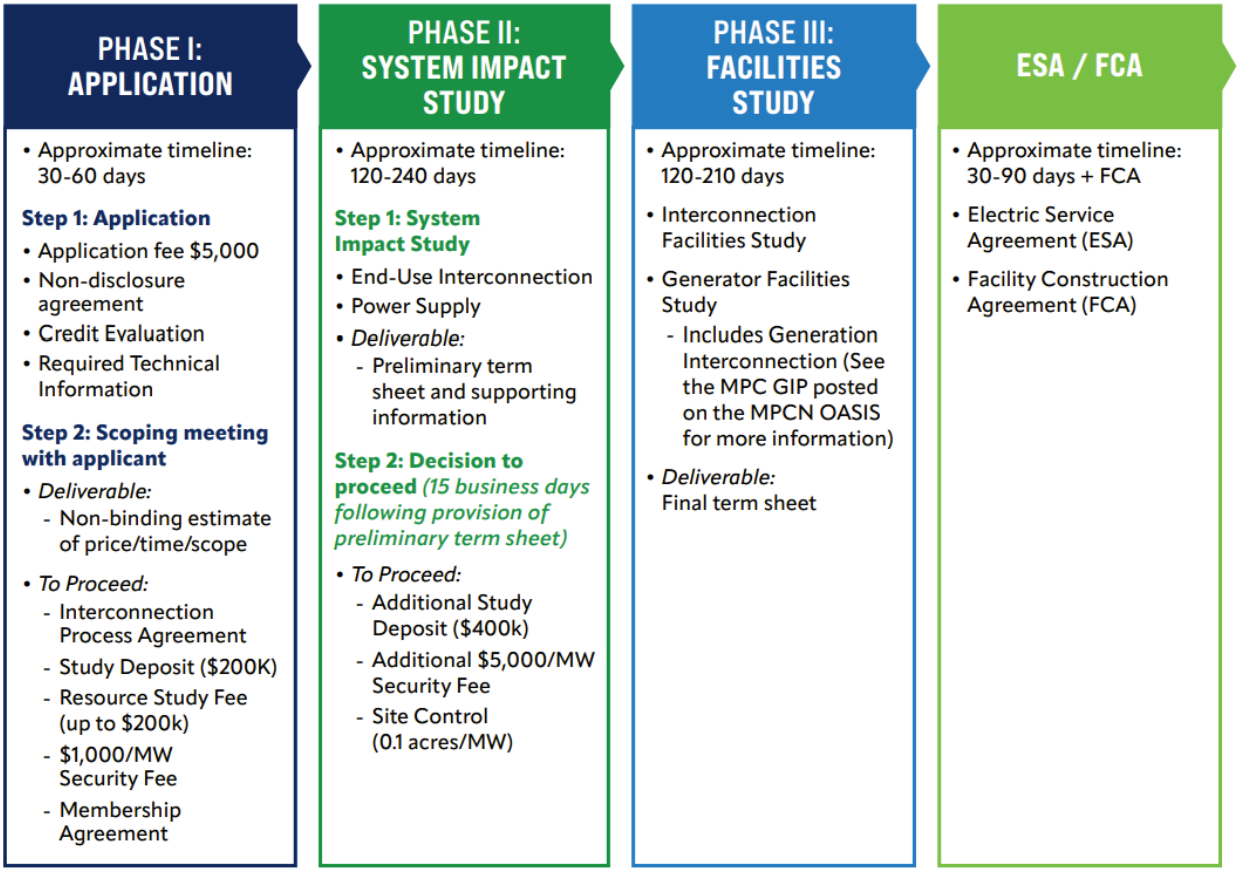
An integrated approach could allow load-generator interconnection requests to be studied based on a net MW withdrawal or injection rate. Whether this is meaningful or desirable may be situation specific. A customer requesting to be studied at a net MW value would need to commit to limiting generation injection on the grid if its load level declines and limiting withdrawal from the grid if generation is unavailable or has a forced outage.

S3.5 Clear disclosure rules for behind-the-meter backup generation and storage. Disclosure and engineering requirements for behind-the-meter generation and storage that is not designed to export to the distribution or transmission system are often vague. Clearer disclosure requirements can improve system operators' visibility and allow for more operator control during system emergencies. Texas' SB6 requires large loads with non-exporting, onsite backup generation equivalent to at least 50% of load to provide information to the interconnecting utility and ERCOT.[52]

S3.6 Standard interconnection process elements. Standard elements of a formal load interconnection process — regardless of what kind of organization manages the process — include discrete steps (or phases), descriptions and timelines for each step, fees at each step, financial readiness requirements, any withdrawal penalties and other penalties, clear customer decision points, information required from interconnection customers, required milestones such as site control and contributions to facilities costs, and *pro forma* electric service and facility construction agreements that specify obligations for different customer sizes. Standard elements of load interconnection processes are comparable to those for generator interconnection.[53] Visuals can provide a helpful way to organize the steps and requirements in load interconnection processes, as illustrated in Figures 6 and 7.

[50] For ISOs that do not have load interconnection processes, this may not be the case.
[51] FERC (2026).
[52] Texas Legislature (2025).
[53] FERC's efforts to standardize generator interconnection processes in *Improvements to Generator Interconnection Procedures and Agreements* (Order 2023) (FERC 2023) can thus also provide a reference for standard large load interconnection.

Figure 7. Minnkota Power Cooperative's Large Load Interconnection Process Summary



Source: Minnkota's large load interconnection process website.

In general, the most time-intensive part of the load interconnection process will be interconnection studies. These studies typically include an impact study, which examines the potential impacts that the load may have on the transmission and distribution systems, and a facilities study, which examines the interconnection facilities and any network upgrades required to interconnect the load. Study timelines may vary based on load size, configuration complexity, and where on the transmission or distribution system the load connects.

S3.7 Cluster studies. Some interconnection providers have established cluster study processes that study multiple load interconnection requests at the same time. Cluster studies may be an efficient way of managing interconnection requests and allocating any network upgrade costs in cases when multiple larger loads are requesting service in the same areas of the distribution or transmission system. However, clustering may also create additional complexity and limit flexibility in the timing of interconnection studies. Interconnection providers could use criteria to determine whether cluster studies are warranted. For instance, PGE's criteria for determining whether a cluster study may be needed is based on size, number of requests, proximity, and location (Figure 8).[54] On an ongoing basis, the utility determines whether cluster studies may be needed based on requests.

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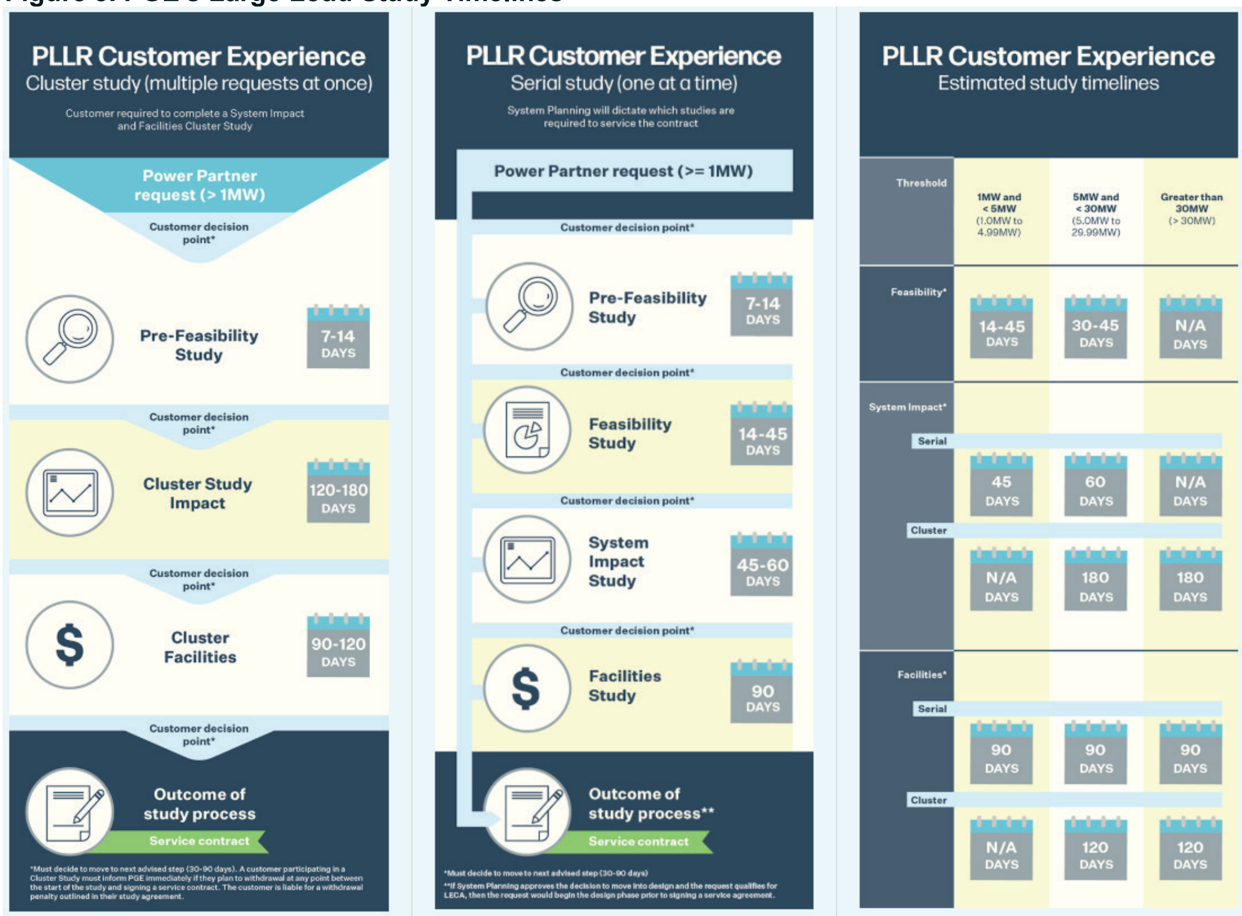
[54] PGE limits cluster studies to loads larger than 5 MW and connection in "enhanced planning areas," which PGE defines as "An area within the Company's service territory where the transmission system

Figure 8. PGE's Large Load Study Timelines



Source: PGE's large load study process website.

S3.8. Interconnection data and queue transparency. Some utilities include information on expected timelines for large load studies and network facilities construction in their interconnection guidelines,[55] but there is limited publicly available information on large load interconnection timelines or costs. Information on expected and actual interconnection timelines and costs could help large load customers make better siting decisions and reduce speculative requests. Publicly available information on actual interconnection timelines and costs could also help to inform large load interconnection policy. Interconnection data transparency could extend to the post-interconnection agreement construction phase.

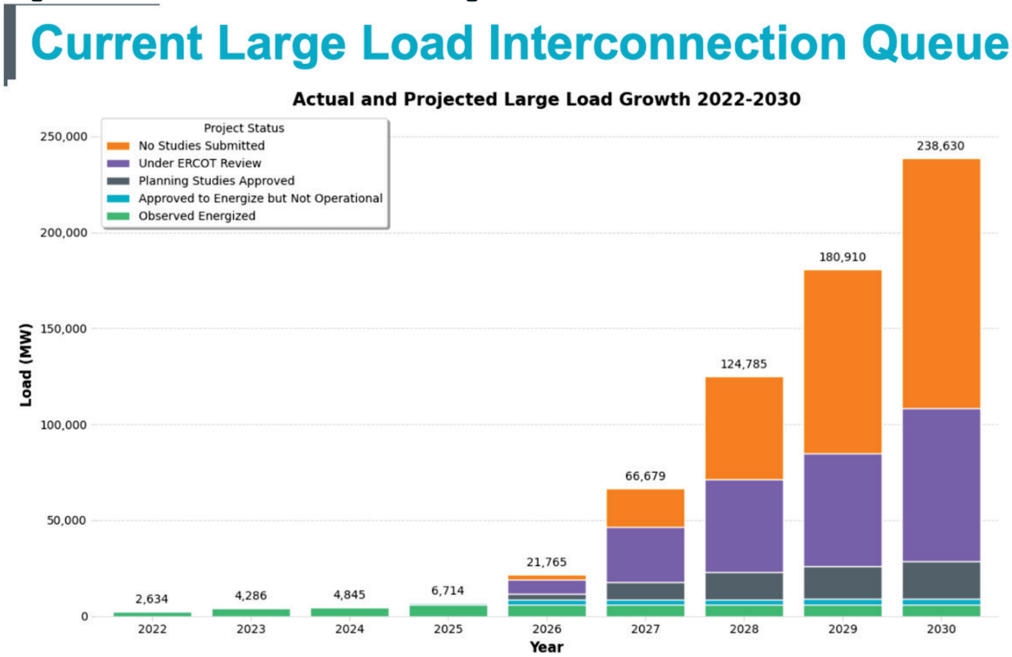
Some transmission providers publish information on load interconnection queues. For instance, ERCOT publishes monthly information on the status of loads in the interconnection queue in its *Monthly Operational Overview* (Figure 9). However, most transmission owners, transmission providers, and distribution utilities do not publish data on load interconnection queues. This type of information can be useful for a range of planning activities: transmission planning, resource adequacy planning, resource planning, and large load customer expansion planning. Recent

requires more complex planning efforts to reliably serve expected capacity requirements." See PGE's large load study process website.

[55] See, for instance, ATC (2025).

improvements in generator interconnection queue transparency could provide insights for the design of large load interconnection queues.[56]

Figure 9. Illustration of ERCOT's Large Load Interconnection Queue Statistics



Project Status	2022	2023	2024	2025	2026	2027	2028	2029	2030
No Studies Submitted	0	0	0	0	2,704	20,341	53,546	95,879	130,303
Under ERCOT Review	0	0	0	0	7,353	28,454	48,171	58,831	79,825
Planning Studies Approved	0	0	0	0	3,181	9,164	14,348	17,180	19,482
Approved to Energize but Not Operational	0	0	0	946	2,759	2,952	2,952	3,252	3,252
Observed Energized	2,634	4,286	4,845	5,768	5,768	5,768	5,768	5,768	5,768
Total (MW)	**2,634**	**4,286**	**4,845**	**6,714**	**21,765**	**66,679**	**124,785**	**180,910**	**238,630**

Source: ERCOT's February 2026 *Monthly Operational Overview* (ERCOT 2026).

4.2.2 Fast-Track Transmission Interconnection Service (Solution Area S4)

The fast-track solutions in solution area S4 (Table 8) all provide avenues for large loads to be connected to the transmission system before there is adequate transmission and generation capacity available to provide constant, reliable service. The kinds of fast-track solutions that might be available to an interconnecting customer will depend on whether and how it is paired with generation.

Table 8. Potential Solutions for Fast Track Transmission Interconnection Service (Solution Area S4)

- S4.1 Provisional interconnection service
- S4.2 Surplus interconnection service
- S4.3 Bring-your-own-generation and pay-for-transmission incentives

[56] For more on recent improvements and ongoing data limitations in generator interconnection, see DOE (2024a).

S4.1 Provisional interconnection service*.* Provisional service, also referred to as conditional service, could include a variety of approaches that allow customers to bring load and paired generation online before network upgrades are completed. Provisional service has an analogue on the generator side: FERC Order 845 requires transmission providers to offer provisional service to interconnecting generators.[57]

The main differences between types of provisional service are their scope (load only or load and generation), whether and when they require loads and generation to be curtailed, how much loads are charged for transmission and RA during the provisional period (full charge or discounted), and the duration of provisional service agreements (time-limited or potentially permanent).

Options for provisional service depend on whether load and generation are paired and, if so, how they are configured. For instance, generation located behind the load's point of interconnection generation may allow for less restrictive provisional service. SPP's proposed Conditional High Impact Large Load Service (CHILLS) and its original HILLGA proposal illustrate the different possibilities for load-generation pairings under provisional service, allowing several load-generation configurations to be studied together and placing more restrictions on generation that is located further from load (Table 9). Loads taking provisional service that do not have paired generation would presumably be subject to more frequent curtailment, whereas loads that have paired generation could reduce necessary curtailment.

SPP's Load Limited Resource Interconnection Service (LLRIS), which FERC approved in January 2026, included the first two HILLGA paths in its proposed tariff revisions, but it did not include CHILLS or the third HILLGA path.[58] LLRIS grants limited interconnection service to generators if they are serving a high-impact large load (HILL), allowing them to be studied serially outside of SPP's normal generator interconnection study process as long as the generators meet LLRIS requirements for sizing and operations. FERC's December 2025 directive to PJM on co-location arrangements also required PJM to "… make clear how Interconnection Customers can make use of provisional interconnection service… to interconnect new generating facilities seeking to serve co-located load."[59] However, it is not yet clear whether PJM's provisional service for co-located load and generation would apply only to the generator, as in SPP's LLRIS, or to the load and the generator in tandem, as in SPP's initial CHILLS and HILLGA proposal.

Provisional service will typically be limited in duration because loads will eventually be expected to transition to network transmission service (see Section 3.2) and generators will be expected to eventually undergo interconnection study and select deliverability status. For instance, under SPP's proposed CHILLS rules, customers would be expected to transition to firm transmission service within five years;[60] under the approved LLRIS, generators are required to undergo a full interconnection study within five years.[61]

[57] FERC (2018).
[58] FERC (2026).
[59] FERC (2025a), p. 4.
[60] SPP (2025a).
[61] FERC (2026).

Table 9. SPP's Proposed CHILLS and Original HILLGA Proposal Rules by Type of Load-Generation Configuration

Load-Generation Configuration	Load Rules	Generation Rules
No generation (HILL/CHILLS)	Load may be subject to curtailment requirements under CHILLS, with curtailment requirements determined through interconnection study; load is not subject to curtailment if CHILLS not selected	No additional rules
Generation located behind the load POI (HILL/CHILLS + HILLGA, path 1, common bus)		No net injections allowed beyond the POI; generator may be subject to additional study if it does not pass an initial screen
Generation located at a different POI but in the same local area (HILL/CHILLS + HILLGA, path 2, local area)		Load and generation are within two buses; generation is capped at load plus a reserve margin
Generation located at a different POI and local area but in the same RA zone (HILL/CHILLS + HILLGA, path 3, deliverability area)		Generation is capped at load plus a reserve margin and has ramp and accreditation requirements

Source: SPP (2025a).

S4.2 Surplus interconnection service. Surplus interconnection service for loads could, in theory, allow customers to add load and co-located generation to an existing POI — subject to a screening study — as long as the net power withdrawal and injection at the POI does not change. For instance, a 50-MW (peak) load could add an additional 10 MW of load and use a combination of scheduling, self-curtailment, behind-the-POI generation, and storage to keep its maximum net withdrawal below 50 MW. To our knowledge, surplus interconnection service has not yet been developed for loads. FERC also directed PJM to clarify how generators seeking to serve co-located load could use surplus interconnection service.[62] Like provisional service, Order 845 also requires transmission providers to offer surplus interconnection service to generators.[63]

S4.3 Bring-your-own-generation (BYOG) and pay-for-transmission incentives. BYOG incentives could help to address resource adequacy concerns in situations in which generation is not able to come online quickly enough to meet demand growth, including from large loads. This situation could occur either because (a) the load is not able to be included in the load forecast used in capacity procurement, or (b) because generation procured bilaterally or through capacity markets cannot be interconnected and built fast enough.[64] BYOG incentives could encourage large loads to find and secure their own generation capacity, rather than relying on LSEs or ISO capacity markets to do so.

In most cases, transmission providers can provide incentives for but cannot force new large loads to bring their own generation. Incentives could include faster interconnection times, as in SPP's LLRIS, exemption from mandatory curtailment rules, as in PJM's proposed expedited process for bring-your-own-new-generation (BYONG),[65] or faster permitting and siting for generation. BYOG incentives will need to balance objectives with fairness concerns.

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[62] FERC (2025a).
[63] FERC (2018).
[64] In principle, if the load forecast is accurate and generation can be interconnected and built within expected timelines, BYOG should be unnecessary for retail customers. However, neither of these conditions will necessarily hold.
[65] See PJM (2026) for more on PJM's BYONG proposal.

Another variant of bring-your-own-resources incentives is to allow faster interconnection for large loads if they agree to pay upfront for transmission facilities costs required for interconnection. PG&E's Rule 30 is an example of this kind of incentive.[66]

4.2.3 Energy Resource Interconnection Service (ERIS) for Loads (Solution Area S5)

Under an ERIS-like interconnection service for loads, loads would make "as available" use of the transmission system. ERIS would be a wholesale interconnection service, meaning that the loads requesting it could be large load customers with direct access to wholesale markets or LSEs requesting ERIS on behalf of retail large load customers. As with generation, ERIS for loads would avoid the need for both RA capacity and the new transmission capacity needed to deliver it. Unlike generators, which forgo RA capacity payments but avoid network upgrade costs with ERIS, a load taking ERIS could avoid both RA and transmission charges. ERIS for loads would likely be implemented differently in ISO and non-ISO regions.

There are multiple potential approaches to implementing an ERIS-like service for loads, though they have not yet been explored in depth. This report groups different approaches in one solution, S5.1 (Table 10). Due to the lack of precedent, the discussion in this section is more exploratory than for other solutions in this report.

Table 10. Potential Solutions for ERIS for Loads (Solution Area S5)

• S5.1 ERIS-like service for loads

S5.1 ERIS-like service for loads. In FERC-jurisdictional ISO regions, generators that request ERIS are not eligible to be credited toward RA requirements. By contrast, generators that request NRIS are eligible to receive RA capacity credits and, if they receive credits, have a must-offer requirement in the ISO energy and ancillary services markets. For loads, the corollary would be that interconnection customers[67] that request ERIS forego receiving some amount of RA capacity, implying that a customer would commit to making that amount of its demand fully curtailable as either (a) manually curtailable during pre-emergency operating conditions or (b) a must-offer bid in the ISO markets. In exchange, the customer could avoid RA charges or both RA charges and any transmission network upgrade charges needed to ensure that generation can be delivered to the load. For consistency, the ERIS amount would not be included in the load forecast for determining RA requirements or, in some cases, transmission needs until the customer requests NRIS and agrees to pay RA and transmission charges.

In non-ISO regions, generators that request ERIS can subsequently access non-firm PTP transmission service (see Section 3.2). Under non-firm transmission service, the generator is subject to curtailment before generators with firm service if the transmission system is congested. For loads, the corollary of ERIS and non-firm transmission service would be that the utility or other transmission provider would have the ability to curtail the large load before doing so for its own native load and other customers with firm service. In exchange, the load would avoid network upgrade charges but, because RA is the transmission customer's responsibility in non-ISO regions, would not avoid RA charges.[68] For consistency, the transmission provider

[66] PG&E (2025).
[67] This customer could be the load or an LSE acting on the load's behalf. This section uses the term 'customer' generically to refer to both.
[68] Outside of ISO regions, transmission providers are not responsible for coordinating or backstopping RA for their transmission customers.

would not include the ERIS load in the load forecast used in its transmission plan. The situations in which ERIS for loads might be used in non-ISO regions would be more likely to involve LSEs that are transmission customers and less likely to involve wholesale loads.[69]

A key question for ERIS-like services for loads is the extent to which loads would be able to avoid transmission charges. In both ISO and non-ISO regions, loads typically pay average (rolled-in) costs rather than incremental costs for use of the transmission system, but in some cases transmission providers charge the "higher of" rolled-in or incremental transmission costs. Similarly, if a transmission provider determines that no network upgrades are needed to serve the load, it could, in principle, charge the load on a short-run marginal cost basis for transmission. More likely, for fairness reasons, transmission charges on ERIS loads would be based on a non-firm transmission rate that includes some embedded costs.

This kind of ERIS-like service is different from traditional demand response. Traditional demand response is a reduction in demand relative to baseline demand. The amount of load in the baseline is still planned for in RA planning and capacity planning on the load side, but the demand response is included on the supply side as an interruptible resource with limited calls and duration. In an ERIS-like service, the load is not planned for and interruptions are not limited in frequency or duration. When the system is capacity constrained, load curtailment could be extensive and service availability would be uncertain.

In ISO markets, ERIS loads could have a must-offer requirement or could be required to be curtailable before conventional demand response resources during system emergencies. A must-offer requirement would need to be for all hours, for instance to submit economic demand bids in both the day-ahead and real-time markets (see box on next page). In non-ISO regions, non-firm service would also need to be in all hours. In both cases, transmission providers would need to create penalties for non-compliance with load "dispatch" instructions.

PJM's proposed non-capacity backed load (NCBL) service bears some similarities to ERIS. In PJM's NCBL proposal, large loads that select or are required to take NCBL service would not be included in the load forecasts used to clear PJM's capacity auction and would not be subject to capacity charges from the auction. In exchange, PJM would be able to curtail NCBL loads during pre-emergency conditions. NCBL would not affect transmission planning or charges.[70] The NCBL proposal was not universally supported by stakeholders.[71]

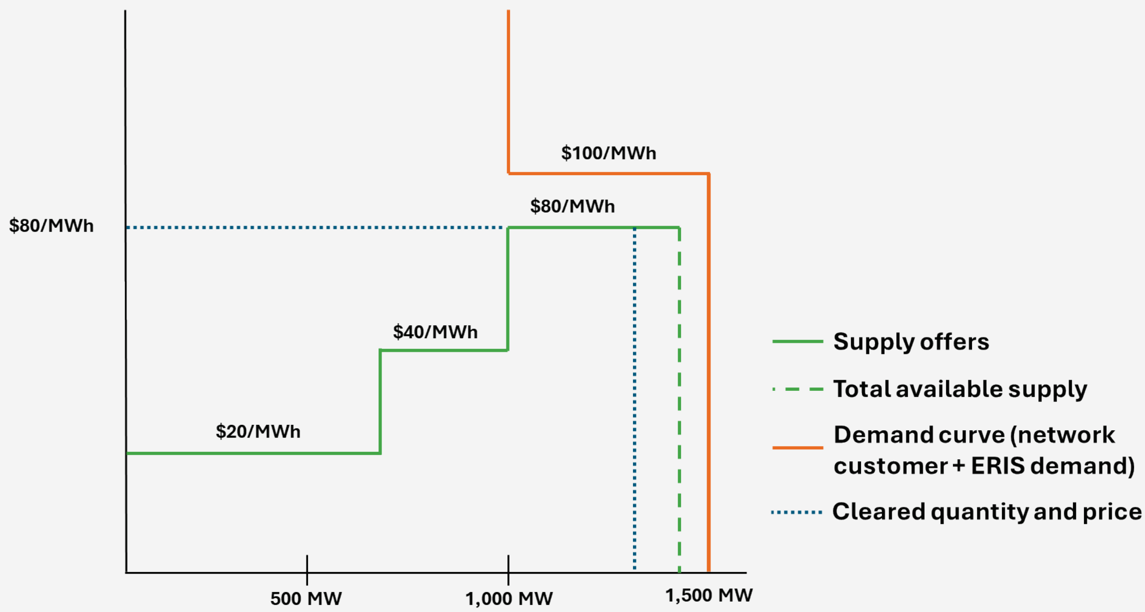
ERIS-like services for loads would require significant changes to existing regulations and markets and would take more time to develop. Whether there is demand for voluntary ERIS-like services for loads is an open question.

[69] Unlike wholesale generators, whether loads can choose to be wholesale or retail customers is regulated by states. Most non-ISO states do not allow direct access. However, there could still be situations in which a large load connects to a municipal utility or rural cooperative's grid and either the utility or customer wishes to use ERIS.
[70] For more detail on this proposal, see PJM (2025c).
[71] See Critical Issue Fast Path – Large Load Additions, Stakeholder Comments. The PJM Board later proposed a "connect and manage" approach to large load interconnection that would retain the curtailment priority aspect of NCBL but would eliminate the exemption from capacity charges (PJM 2026).

ERIS and Must-Offer Requirements for Loads

In ISO markets, a large load with ERIS could be required to submit economic bids into the day-ahead and real-time markets (see solution area S9, Section 4.4.1). Most utility and other retail loads are network customers and are self-scheduled (quantity but no price bid) in the ISO markets, which means that these loads will clear the market before any economic bids. The ISO clears all demand bids in the market and sends instructions to ERIS customers on the amount of power they have cleared in the market and can withdraw from the transmission system.

In a situation where there is insufficient supply available, as in the below example, the ISO would curtail the ERIS customers' and all other economic demand bids down to the point at which the market can clear again. In the example, network customers have 1,000 MW of demand in a vertical demand bid. ERIS customers have 500 MW of demand with a $100/megawatt-hour (MWh) bid, exceeding the 1,400 MW of available supply. The ISO clears the energy market at 1,300 MW ($80/MWh) to maintain 100 MW of reserves. ERIS customers are thus able to consume 300 MW of their 500 MW bid, with 200 MW of *pro rata* load curtailment.



For must-offer requirements on loads to be effective, loads would need to be able to bid into real-time markets, as the cleared amount must be both financially and physically binding, with penalties for withdrawing more or less than the real-time cleared amount. Presently, in most ISOs, loads can only bid into day-ahead markets, which are voluntary, and there are no penalties for loads other than real-time settlement charges if they withdraw more or less than their scheduled amount. Implementing a must-offer requirement for loads would thus require changes in market design.

4.2.4 Flexible Interconnection (Solution Area S6)

On the distribution system, curtailable load and generation service has typically been referred to as 'flexible interconnection.' Like the solutions in S4 and S5, flexible interconnection allows (a) loads to more quickly connect to the distribution or sub-transmission system before the interconnection facilities and network upgrades that would be needed to reliably serve them at all times have been completed, and (b) utilities and customers to reduce costs by right-sizing network and customer equipment. Unlike the solutions in S4 and S5, flexible interconnection tends to be retail customer-focused and state jurisdictional. More sophisticated approaches to flexible interconnection may require piloting.

This section is organized around three broad categories (Table 11) of flexible interconnection: staggered connections (S6.1), static flexible interconnection (S6.2), and dynamic flexible interconnection (S6.3).[72]

Table 11. Potential Solutions for Flexible Interconnection (Solution Area S6)

- S6.1 Staggered connections
- S6.2 Static flexible interconnection
- S6.3 Dynamic flexible interconnection

The technology, engineering, and regulatory fundamentals behind flexible interconnection were initially developed for distributed PV generation but can be extended and adapted to large loads. Approaches to flexible interconnection have thus far varied and will likely continue to vary across states.

S6.1 Staggered connections. Staggered ("bridge-to-wires") connections allow customers to energize load in a stepwise fashion as needed upgrades are completed. For instance, a utility might inform a customer that, in the near term, it could only accommodate 10 MW of new load, but that once a substation is upgraded in two years it could accommodate the customer's full 20-MW load. The customer could stagger its load additions, initially adding 10 MW and then adding the final 10 MW once upgrades are complete.

Staggered connections could be facilities that are built and energized piece by piece, or they could be facilities that are completed and energized piece by piece. Utilities have long done informal staggered interconnections for customers that complete their projects in stages, but staggered interconnection could also be more formalized where it is not yet formal.[73] In cases where projects are completed and then energized in pieces, the customer must sign up for temporary limits on grid imports, either static (S6.2) or dynamic (S6.3).

S6.2 Static flexible interconnection. Static flexible interconnection limits load or generation to a MW amount that is fixed monthly, seasonally, or annually.[74] This limit will typically be below the maximum total demand of all of the customer's equipment, if summed up individually. For instance, a customer that has 20 MW of maximum total demand may be able to optimize its operations so that its maximum concurrent demand from the grid is only 15 MW. Customers

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[72] These categories and the content in this section draw heavily on GridLab (2026a).
[73] Formalization can help to set customer expectations and ensure utility safety. Formalization means that utilities have documented rules for eligibility, process, and when loads will be able to fully energize.
[74] Distribution utilities have historically focused on peak demand periods in studies of new load connections. Setting fixed seasonal or monthly limits requires studying more time periods.

must install equipment that limits imports from the grid to this amount, according to utility enforcement rules.

There are several approaches to enforcement. Customers can install certified power control systems that limit grid imports and exports, relays that trip customer connections to the grid, or customized equipment that ensures limits will be respected to the satisfaction of the utility. Rules, roles, and responsibilities for enforcing static limits must be well documented, and utilities must be able to inspect equipment to verify that limits will be enforced.

Many state interconnection rules allow static export limits for generation, in the form of non-export or limited export rules.[75] Static import limits are not common for loads, but in principle, they could use the same technologies and enforcement rules.

California utilities' static flexible interconnection
PG&E's load limit letter establishes annual, seasonal, or a combination of seasonal and time-of-day limits on load imports from the grid. SCE's load control management systems pilot establishes time-of-year and time-of-day limits.[76]

S6.3 Dynamic flexible interconnection. Dynamic flexible interconnection sets import limits on loads that vary over time, from weeks to minutes before operating intervals. Relative to static limits, dynamic limits allow utilities to better optimize distribution infrastructure costs and customer use of the distribution and sub-transmission systems, but they require significant changes in distribution operations. With dynamic limits, the utility can either directly control the load or can set operating limits and require customers to follow the limits or face penalties. Both approaches require more active utility management of distribution systems than has been traditionally the case, including more visibility, communications, and control, and more sophisticated metering and settlement.[77] Utilities must also provide enough certainty in curtailment schedules before customers interconnect to allow for reasoned choices and avoid disputes.

Dynamic flexible interconnection has thus far mainly focused on distributed generation,[78] though some jurisdictions have piloted or discussed dynamic limits for EVs.

Examples of dynamic flexible interconnection for loads
PG&E's Flex Connect program has used a distributed energy resource management system (DERMS) to set day-ahead hourly limits for power consumption for EV charging, in cases where additional infrastructure needs would be have significantly delayed charging projects. National Grid's Charge Smart Plan uses a DERMS system to directly, actively control EV charging for subscribed customers.

[75] One of the earliest examples was California's Rule 21. For a list of states with regulations for non-exporting solar systems, see Craftstrom Solar (2025).
[76] Descriptions are from Section 3 of CPUC (2025b).
[77] DOE (2024b).
[78] Example pilots include Avangrid's Flexible Interconnection Capacity Solution, ComEd's demonstration pilot (Mendota region), and National Grid's Active Resource Integration Pilot. See DOE (2024b) for descriptions.

4.2.5 Large Load Construction of Transmission and Distribution Facilities (Solution Area S7)

Once large load customers have signed a service agreement, they must wait for the construction of facilities that physically connect their loads to the distribution or transmission system, as well as any upgrades to the distribution and transmission systems needed to reliably serve their loads. Construction of these facilities can be costly and time-consuming. The solution in S7 (Table 12) aims to accelerate timelines and reduce costs associated with the construction of these facilities.

Table 12. Large Load Construction of Transmission and Distribution Facilities (Solution Area S7)

• S7.1 Option to build

S7.1 Option to build. On the generator side, FERC's Order 845 (2018) required transmission providers to allow connecting customers to build interconnection facilities and "standalone" network upgrades — often interpreted to mean upgrades that can be completed without taking other facilities out of service.[79] This "option to build" could be extended to larger interconnecting loads as well as generators.

The most important obstacles to the option to build are (1) utility concerns over construction quality and potential impacts to the reliability of their systems, and (2) questions of whether utilities should be allowed to own and earn a return on these facilities and whether they should be eligible for cost-sharing. Barring standardization, approaches to resolving these two issues may reasonably differ across jurisdictions. However, in all jurisdictions, it is unlikely that utilities will provide customers with an option to build without a regulatory requirement to do so.

The Pennsylvania PUC's Tentative Order on *Interconnection and Tariffs for Large Load Customers* included extensive discussion on whether loads should have an option to build ("self-construct" in the Order).[80] This option was included in the state's model tariff for large loads, though the commission did not reach a decision on whether utilities should be permitted to earn a return on facilities built by loads and whether cost sharing would be allowed.[81] PG&E's Rule 30 includes an option to build.[82] Some utilities provide a generic option to build for interconnection customers, without specifying whether it is for generators or loads.[83]

4.3 Utility Procurement

Regulatory processes established to provide consumer protections may also slow the large load connection process. For example, supply chain delays may be exacerbated because often utilities cannot procure equipment in advance of project approval. Similarly, competitive bidding requirements, intended to ensure least cost procurement, may last longer than desired and unintentionally delay load connections. Innovative approaches to address these challenges can be explored to expedite the utility procurement process while maintaining robust consumer protections.

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[79] Order 845 gives interconnection customers the option to build even if a transmission provider could meet construction deadlines (FERC 2018, pp. 44–71). Under Order 845-A, a transmission provider must explain why a network upgrade is not a standalone network upgrade (FERC 2019, p. 7).

[80] PAPUC (2025).

[81] *Ibid.*

[82] PG&E (2025).

[83] An example can be found in section 3 of Dominion Energy Virginia's Facility Interconnection Requirements (Dominion Energy, 2026).

Table 13. Resource Planning and Procurement Solution Area

Solution Area
S8. Utility procurement approaches

4.3.1 Utility Procurement Approaches (Solution Area S8)

The solutions in this section (Table 14) focus on providing utilities limited flexibility to procure equipment in advance of need (S8.1) and procure new resources of any type outside of normal planning and procurement cycles in cases where regulatory constraints limit their ability to do so (S8.2).

Table 14. Potential Solutions for Utility Procurement Approaches (Solution Area S8)

- S8.1 Advance procurement of equipment
- S8.2 Flexible procurement for new resources

S8.1 Advance procurement of equipment. Regulated investor-owned utilities are typically only allowed to include costs in customer rates after they incur those costs, the costs are determined prudent, and the equipment is in service (used and useful). Supply chain constraints can create challenges with this approach during periods of load growth, as equipment deliveries may be delayed and utilities may be hesitant to buy equipment before it is needed due to cost recovery concerns. One option to address this issue is for PUCs to approve funding for utilities to procure equipment in advance of need, with limits on spending and other rules that reduce stranded cost risks.[84]

Xcel Energy's Strategic Resilience Reserve Fund
The fund, approved by the Colorado PUC in 2025 (Colorado PUC, 2025), allows for early procurement of transformers and breakers. Xcel Energy procures the equipment, but it is available to third parties that participate in Xcel Energy's request for proposals for new resources. The Colorado PUC capped Xcel Energy's spending under the fund at $200 million.

S8.2 Flexible procurement for new resources. Many states require regulated utilities to procure new generation resources through competitive solicitations. The solicitation often follows a resource planning process, such as an IRP, that determines the quantity of resources that will be procured. A timing mismatch may occur between these planning-procurement cycles and resource needs for large load customers, if large loads wish to come online between cycles. To address this challenge, PUCs can allow for more flexibility with respect to the timing of resource procurement, subject to criteria and safeguards that limit the ability to circumvent competitive procurement rules.

Xcel Energy's Incremental Need Pool
The pool, approved by the Colorado PUC in 2025 (Colorado PUC, 2025), allows Xcel to acquire resources in between its established procurement cycles. The pool can be activated under two circumstances: (1) if an approved project fails or (2) if a new large load executes an electric service agreement and interconnection agreement.

[84] For more on the opportunities and risks of proactive investment more generally, see GridLab (2026b).

Another approach to allow utilities to acquire resources to serve large loads out of procurement cycles is through procurement through wholesale markets and market-based tariffs, discussed in Section 4.5.

4.4 Markets and Operations

Market and operations solutions can resolve operational issues that would otherwise create connection obstacles for large loads and are more cost-effectively managed at the system level rather than through changes in interconnection requirements. For instance, preemptively addressing concerns about the potential impact of large loads on operating reserve needs could reduce the chance that these concerns become a bottleneck for load growth. The solutions in this section focus on changes in energy markets and transmission service (S9) and operating reserves (S10). Large loads may wish to provide an array of energy and reserve market services either to reduce their own costs or to accelerate connection timelines. Allowing them to do so could lower costs for other customers as well.[85]

Table 15. Markets and Operations Solution Areas

Solution Area
S9. Energy markets and transmission service
S10. Operating reserves

4.4.1 Energy Markets and Transmission Service (Solution Area S9)

The solutions in S9 (Table 16) aim to provide greater operational flexibility through changes in real-time energy markets (S9.1), in ISO regions, and transmission service (S9.2). S9.1 and S9.2 are also related to the ERIS solution (solution area 5, Section 4.2.3).

Table 16. Potential Solutions for Energy Markets and Transmission Service (Solution Area S9)

- S9.1 Load participation in real-time markets
- S9.2 Non-firm transmission service for loads

S9.1 Load participation in real-time markets. In wholesale energy markets, loads can voluntarily participate in day-ahead markets but have limited options for participation in real-time markets. The lack of load participation in real-time markets creates several challenges, including intra-day commitment challenges due to large differences between day-ahead hourly forecasts and 5-minute real-time load, and large minute-to-minute supply-demand imbalances due to price “chasing” by loads.[86] Enabling and encouraging load participation in real-time markets could help to both address these issues and support an ERIS-like service for loads (S5.1), but this may require extensive changes in market rules, design, software, settlement, operational procedures, and real-time operating reserves.[87]

[85] For more on large load integration into markets and operations, see ESIG (2026b).
[86] Price chasing refers to when loads increase or decrease demand shortly before or after real-time market clearing in response to posted real-time prices. This decreases the cost to the load but often does not affect real-time price formation (if the load is still in the real-time forecast) and creates additional swings in demand within dispatch intervals that must be managed using regulation reserves.
[87] Load participation in real-time markets would also likely require load settlement at nodal locational marginal prices and additional regulation reserves to manage the difference between system operator load forecasts and real-time demand bids.

S9.2 Non-firm transmission service for loads. The FERC OATT establishes non-firm transmission service for generation but not for loads (Section 2.3.2). Creating non-firm transmission service for loads could provide additional flexibility for large loads and transmission providers. Non-firm transmission service would overlap with ERIS, as described in Section 4.2.3 (S5.1). Unlike ERIS, however, loads could, in principle, access non-firm transmission service at different points in time rather than only through interconnection.

As an example of how non-firm transmission service could be used, consider a case in which a new large load requests to connect to the sub-transmission system of a rural cooperative that already has an existing large load. The new large load would require extensive network upgrades for providing firm transmission service, but the existing large load expresses a willingness to take non-firm transmission service, at least in the short term, in exchange for a reduction in transmission rates. Curtailment would be directed by the transmission provider and would avoid the need for upgrades. Non-firm transmission service might limit pressure on the transmission provider's transmission rates, while also giving the transmission provider the security to curtail the coop's existing large load in cases where the system is congested and the transmission provider's available resources are unable to serve the load.[88]

ISO regions do not offer physical transmission rights, which suggests that non-firm transmission service for loads would require settlement at nodal locational marginal prices in ISO regions and, like ERIS for loads discussed earlier, some form of curtailment obligations in the ISO markets. In non-ISO regions, curtailment obligations and priority would presumably be tied to physical transmission rights.

Non-firm transmission service for loads would likely require changes to the FERC OATT. It would also require that transmission providers have the ability to directly control and curtail loads or send them curtailment instructions and enforce penalties for non-compliance. Whether there would be demand for non-firm transmission service in practice is an open question.

4.4.2 Operating Reserves (Solution Area S10)

Operating reserves include reserves to manage the loss of generation supply (contingency reserves) and variability within dispatch intervals (frequency regulation). The solutions in S10 (Table 17) aim to ensure that operating reserves are adequate to manage large load demand variability (S10.1, S10.2) and to fairly allocate the cost of any additional required reserves (S10.3).

Table 17. Operating Reserves Potential Solutions (Solution Area S10)

- S10.1 Changes in regulation reserve procurement
- S10.2 Downward contingency reserves
- S10.3 Changes in reserve cost allocation

S10.1 Changes in regulation reserve procurement. Regulation reserves are designed to manage short-term supply-demand imbalances after the system operator has sent dispatch instructions to generators. In at least one instance (in ERCOT), large loads have introduced short-timescale variability that has exceeded a system operator's regulation reserves.[89] If large

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[88] Currently, if the rural cooperative requests non-firm transmission service for the generation supplying the large load, the transmission provider would be obliged to serve the load and charge imbalance costs for any deviations from scheduled generation. As the scale of imbalances increases, this approach becomes less tenable.

[89] See ERCOT (2024) (p. 20 in slides for NERC's Large Load Task Force kickoff meeting).

loads do introduce higher levels of variability on short timescales, transmission providers (balancing area authorities) could increase their procurement of frequency regulation reserves, potentially in tandem with establishing operating ramp rate limits for large loads. Determinations of whether to increase regulation procurement or change methods for setting regulation reserves could be done through system studies, using a combination of historical operating data and modeled simulations. Loads should also be eligible to provide regulation reserves, which is already the case in some ISOs.

S10.2 Downward contingency reserves. Contingency reserves are designed to manage the loss of a large generator — they are upward reserves. However, the sudden loss of a large load could create over-generation conditions (including high frequency) that system operators would not be able to resolve without the flexibility to rapidly dispatch generation downward. If downward dispatch would require turning off units, it could lead to temporary generation shortfalls. One strategy for addressing this issue would be for system operators to hold downward contingency reserves, to ensure that there is sufficient downward flexibility to manage the loss of a large load. Downward contingency reserve costs could be allocated based on cost causation.

S10.3 Changes in reserve cost allocation. Typically, wholesale operating reserve costs are allocated on a load ratio share basis and are bundled in retail rates for retail customers. This approach balances simplicity and cost causation. It assumes that no one customer or customer class disproportionately affects operating reserve costs and that allocation methods that are more aligned with cost causation will not incentivize customers to reduce their reserve needs. If these assumptions no longer appear to be appropriate, it may be helpful to explore alternative methods for cost allocation. More granular cost allocation methods may better align reserve cost allocation and cost causation, but they would also increase operational, metering, and market settlement complexity.

4.5 Cost Allocation and Ratemaking

Addressing cost allocation challenges and risks posed by large loads on a case-by-case basis or waiting until they become larger problems can create obstacles to large load connection. The solutions in this section aim to create transparent, stable, and robust cost allocation methods and terms and conditions for service. They are organized around three strategies: changes in cost allocation methods (S11), large load tariffs (S12), and wholesale service for large loads (S13).

Table 18. Cost Allocation and Ratemaking Solution Areas

Solution Area
S11. Cost allocation methods
S12. Large load tariffs
S13. Wholesale rates and access for large loads

At the core of concerns about the rate impacts of large loads are two key factors. The first is large loads' impact on costs (the numerator in rates). Large loads could impact costs by (a) requiring new generation, transmission, and distribution infrastructure investments or changing the unit costs of those investments; (b) changing the cost of operating and maintaining the electricity system; and (c) changing staffing, software, and other administrative costs. The second factor is large loads' demand for capacity and energy over time (the denominator in rates). Large loads' actual demand, relative to their expected demand, will depend on a range of performance characteristics: time to full project capacity, load factors, and the length of time that the customer takes service.

The interplay between these two factors determines rate impacts and how costs are ultimately allocated among different kinds of customers. How to balance the opportunities and risks presented by these two factors is a theme that appears throughout the solutions in this section.

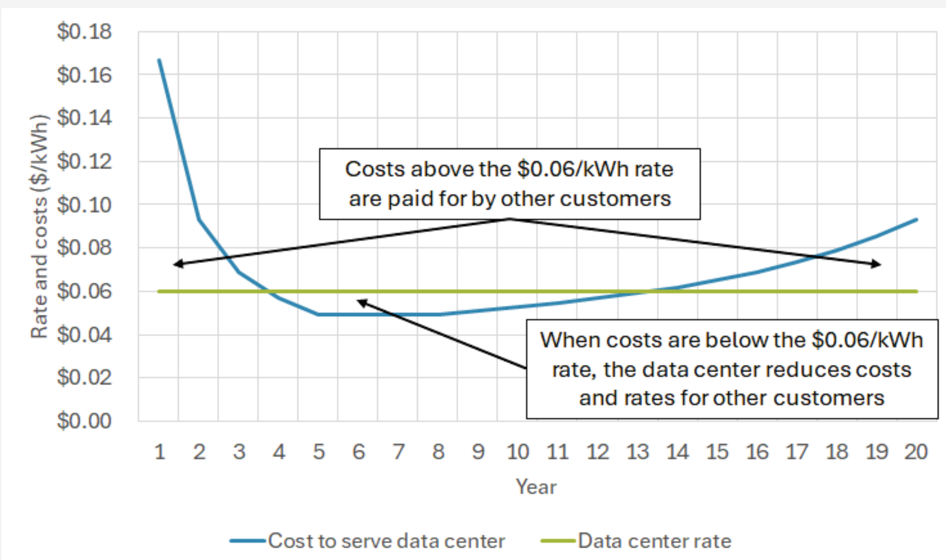
Another theme that recurs throughout this section is whether the costs to serve large loads should be allocated on an incremental or average cost basis. Incremental costs are the cost of new generation, transmission, distribution, and other costs needed to serve the new load. Average costs are total costs, including new costs, divided by total demand, including the new customer demand. The box below illustrates the difference between these two kinds of costs, and the applications of FERC's "higher of" policy, in the context of wholesale transmission rates. The underlying fundamentals are similar for bundled retail rates.

Costs, demand, rates, and cost allocation

Consider a utility that builds a new 600-MW power plant to serve a data center that is expected to have a 500-MW peak demand and a load factor of 0.8 (3,504 gigawatt-hours [GWh]/yr). The power plant costs $150 per kilowatt (kW) per year ($150/kW-yr) to build and costs $20/MWh to operate. The utility negotiates a volumetric rate of $0.06/kWh with the data center,* higher than the $0.046/kWh cost* of using the power plant to serve the data center given its expected peak and energy demand.

The utility completes the power plant in the same year that the data center begins operation, but the data center only brings 100 MW of load online in year 1 and gradually adds 100 MW per year, reaching 500 MW five years after the power plant is built. The data center's load factor is lower than anticipated (70% rather than 80%). In year 8, the data center begins to use new technologies that reduce its peak and energy needs, which are 60% lower in year 20 than originally anticipated.

If the data center's demand is close to expected, the cost to serve the data center will be below the $0.06/kWh rate and revenues from the data center will exceed the cost to serve it, lowering costs and rates for other customers (see figure). However, lower-than-expected data center demand means that the cost of using the power plant to serve the data center (per kWh of sales to the data center) will be higher than expected. Any costs that exceed the $0.06/kWh rate for the data center will need to be paid for by other customers or disallowed.



In this example, in present value terms (8% discount rate), the costs to serve the data center exceed revenues by around $20 million over the 20-year financial lifetime of the power plant. At a rate of $0.061/kWh, however, present value revenues would exceed costs. The solutions in this section represent different approaches to addressing these kinds of opportunities and risks.

* This example is intended to be simplified. Typically, large industrial customers will have demand charges and other terms and conditions that are not considered in the example. The $0.046/kWh cost to serve the data center is calculated as the $90 million/yr fixed cost (= $150/kW-yr × 600 MW × 1,000 kW/MW) divided by expected data center energy demand ($0.026/kWh = $90 million/yr / [3,504 GWh × 10^6 kWh/GWh]) plus the operating cost of $20/MWh ($0.02/kWh).

Average costs, incremental costs, and "higher of" policy

Consider a utility that has a $5.00 per peak kW per month ($/kW-mo) transmission charge, 5,000 MW of peak demand, and 26,280 GWh of annual energy demand (60% system load factor). The utility's annual transmission revenue requirement (ATRR) is $300 million per year (= $5.00/kW-mo × 12 mo/yr × 1,000 kW/MW × 5,000 MW) and its volumetric transmission costs are $11.42/MWh (= $300 million/yr / [26,280 GWh × 1 GW/1,000 MW]). The ATRR is based on average costs.

The utility is evaluating a 500 MW (peak) data center request, with an expected annual energy demand of 3,504 GWh/yr (0.8 load factor). The data center would trigger incremental transmission costs of $20 million per year, equivalent to an incremental cost of $3.33/kW-mo and $5.71/MWh. Adding the data center would increase the utility's ATRR to $320 million per year (= $300 million/yr + $20 million/yr) but would reduce its average transmission charge to $4.85/kW-mo and its volumetric transmission rates to $10.74/MWh (6% reduction). The lower volumetric rate results from incremental costs ($3.33/kW-mo), which are lower than average costs ($5.00/kW-mo), and from the data center's relatively higher load factor (80% versus 60% for the utility).

The utility could charge the data center either (a) the incremental cost of the transmission upgrade ($3.33/kW-mo), or (b) "rolled-in" (average cost) rates based on total costs ($4.85/kW-mo). FERC allows transmission providers to charge customers the "higher of" a monthly incremental transmission rate or a monthly average (embedded) transmission rate.* As described below, some state PUCs are also directing utilities to use "higher of" cost allocation.

* FERC Order 888 (FERC 1996) established the "higher of" pricing policy. FERC Order 890 clarified that "higher of" rates should be based on a monthly incremental rate or a monthly embedded rate (FERC 2007).

4.5.1 Cost Allocation Methods (Solution Area S11)

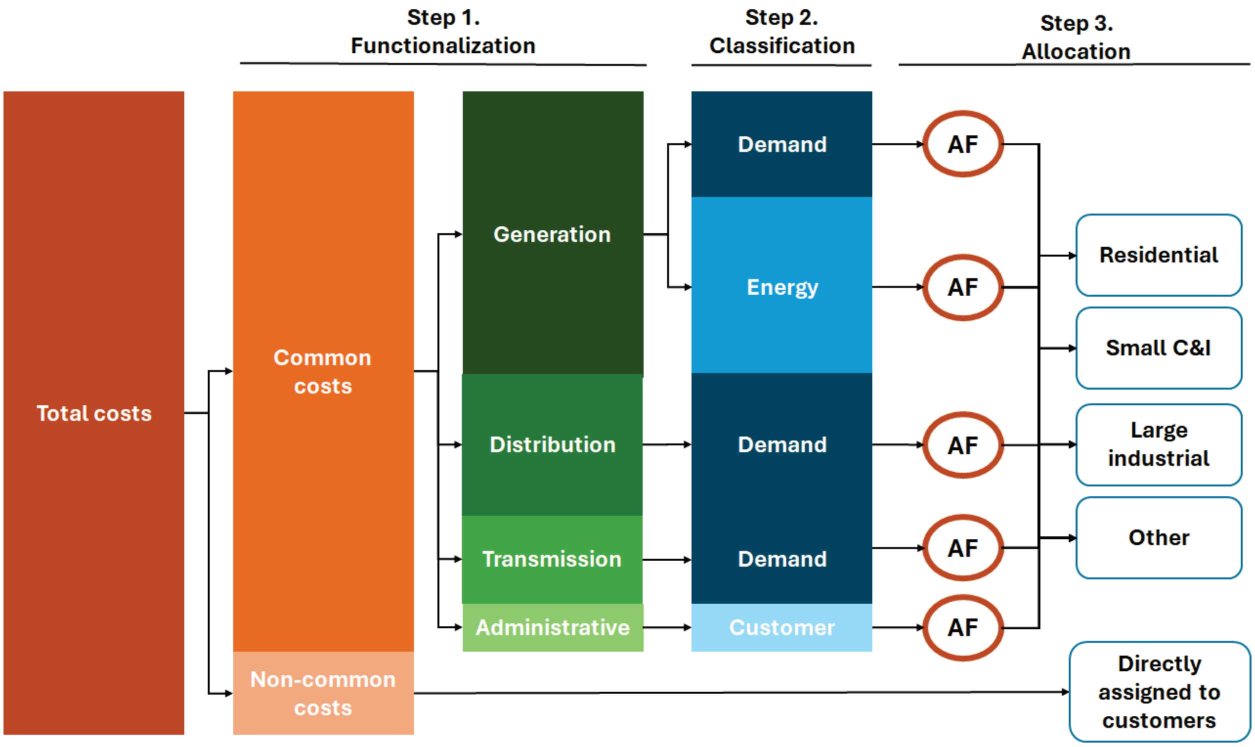
The solutions in S11 (Table 19) aim to ensure balanced cost allocation between large loads and other customers. They include reviewing and updating the factors used to allocate costs in ratemaking, if needed (S11.1), and directly assigning costs in cases where it might be justified (S11.2).

Table 19. Potential Solutions for Cost Allocation Methods (Solution Area S11)

- S11.1 Review and update of allocation factors
- S11.2 Direct assignment of costs

As background for this solution, within the ratemaking process, cost allocation typically occurs through three main steps, illustrated in Figure 10. Step 1 (functionalization) categorizes costs into shared ("common") and non-common costs and assigns common costs to functional categories (generation, transmission, distribution, and administrative). Step 2 (classification) classifies functionalized costs by causal factors (demand, energy, customer). Step 3 (allocation) allocates the classified functional costs to customer classes on the basis of allocation factors — for instance, transmission capacity costs may be classified as demand and allocated according to a class's share of peak demand — and directly assigns non-common costs to specific customers.[90] In considering potential changes to rates, the main areas for utilities and commissions to review are in step 3 (allocation factors, direct assignment) and step 1 (categorization of non-common costs).

Figure 10. Illustrative Overview of Cost Allocation for Regulated Utilities



Notes: AF is allocation factor. Residential, small C&I (commercial and industrial), large industrial, and other are customer classes. This figure is meant to illustrate a general approach — not all utilities follow these steps or use the categories or rate classes in the figure.

S11.1 Review and update of allocation factors. Allocation factors attempt to align cost allocation with cost causation or beneficiaries. For instance, generation fuel costs are typically allocated to different customer classes based on the share of each class's energy (GWh) demand, because fuel costs are variable and driven by energy demand. A review of large load impacts on cost allocation could, in principle, include the full range of allocation factors, though in practice, much of the focus may be on capacity (fixed) cost allocation.[91]

Large load customers with high load factors, in particular, have the potential to stress existing cost allocation methods because their incremental generation and transmission capacity costs may be significantly higher than average capacity costs. These kinds of customers may trigger the need for new baseload generation, which tends to have significantly higher than average

[90] Direct assignment of costs could be based on cost causation or beneficiary pays. This step in the ratemaking process will also often involve allocating costs to different time periods for use in time varying rates. For more detail on the cost allocation and ratemaking processes see Lazar (2016) and Lazar et al. (2020).

[91] Allocation factors might include, for instance, coincident and non-coincident peak shares for demand costs, energy consumption shares for energy costs, and customer count shares for administrative costs.

capital costs but lower than average energy costs.[92] Using factors for allocating demand (capacity) costs that are oriented toward a limited number of peak demand periods may lead to an under-collection of costs from high load factor customers relative to cost impact, because these customers' capacity needs are spread out across the year rather than concentrated in a limited number of hours.[93] Whether cost shifting will occur in practice can be determined through analysis.

Several jurisdictions are reviewing cost allocation and considering changes to cost methods to better align allocation and causation, as illustrated in the box below, though in many cases, utilities and PUCs are still in the exploratory phase.

Changes in cost allocation methods

In Texas, the PUCT is considering if allocating transmission costs based on the highest four coincident peaks (4CP) is still appropriate, or if it creates a structure where certain customers, such as data centers and cryptocurrency customers, can avoid paying their fair share of transmission costs (Docket 58484).

The Virginia State Corporation Commission (SCC) ordered Dominion to explore alternatives to its existing methodology for allocating generation plant costs, and to include class cost of service studies in its next biennial rate review. The SCC also ordered Dominion to examine transmission cost allocation in its next rate proceeding and to develop and propose alternative cost allocation approaches (Case PUR-2025-00058).

PGE proposed adjusting its marginal cost of service study to include a "peak growth modifier," which will allocate transmission and fixed generation costs to customers contributing to system *growth*, not just peak demand in the test year. If approved, costs will be allocated based on both coincident peak demand and peak demand growth (Docket UM 2377).

The Michigan Public Service Commission required Consumers Energy to file six prescriptive cost allocation and rate design proposals in its next rate case, including changes from allocation based on four coincident peaks (4CP) to allocation based on monthly coincident peaks (12CP) (Case U-21859).

S11.2 Direct assignment of costs. Utilities can address concerns over the cost impacts of new infrastructure requirements by directly assigning some or all of those costs to large loads. For large loads, directly assigned costs could include the cost of facilities to connect load to the grid (interconnection facilities) but also could include the costs of new generation, transmission, and distribution capacity that would not have been planned and built *but for* the new customer or customers.[94]

Direct assignment of most or all interconnection facilities costs tends to be more straightforward because these facilities do not benefit other customers, but direct assignment of *but for* costs often requires more thoughtful application. *But for* infrastructure may eventually benefit other

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[92] A similar situation may occur with transmission needs that are triggered in studies of non-peak load levels.

[93] Cost shifting can occur even in situations in which adding new baseload generation would reduce total average volumetric costs, if the increase in capacity costs for existing customers outweighs the reduction in energy costs.

[94] In other words, *but for* costs are the costs that are necessary to provide service for the new customer.

customers, even if it is determined to not do so when a large load customer connects, which means that direct assignment of costs may be discriminatory and advantage some kinds of customers over others.[95] Similarly, future infrastructure investments may benefit a large load customer, which may question the fairness of paying for that infrastructure if it was already direct assigned *but for* costs.

Direct assignment of *but for* costs also raises questions about whether incremental or embedded cost pricing provides the right balance between opportunity and risk, as discussed earlier in this section. Direct assignment of costs could be voluntary and tied to incentives, as the PG&E example below illustrates. If costs are directly assigned to a larger group of customers, utilities may need to create a new rate class with which to assign costs.

Customers can pay for directly assigned costs through rates, through upfront payments, or through other instruments. A risk of directly assigning costs to large loads and collecting these costs over time is that termination of large load service will shift any uncollected sunk costs to other ratepayers. Strategies for addressing these longer-term cost recovery risks include tariff and contract terms and conditions (S12) or shifting large load customers to wholesale rates (S13).

Direct assignment of costs

East Kentucky Power Cooperative (EKPC) requires large loads to pay for all costs incurred: "Qualifying Customers are responsible for paying 100% of all costs, expenses, losses, and liabilities incurred or expected to be incurred by EKPC or the Cooperative for new or upgraded local/regional transmission facilities, distribution facilities, and related infrastructure, including substations, necessary to reliably and safely serve the data center" (Case 2025-00140).

PG&E's Electric Rule 30 allows customers who voluntarily pay for transmission infrastructure work upfront an accelerated pathway to connect to PG&E's transmission system.[96]

The Michigan PSC required Consumers Energy to consider a direct assignment of costs to a new large load customer rate class in its next rate case. Direct assignment could include transmission, generation, and distribution costs (Case U-21859).

Another option for allocating costs is a "crediting policy," which is required for large generators in FERC's *pro forma* Large Load Interconnection Agreement (LGIA).[97] Under the LGIA's crediting policy, interconnection customers to initially fund the costs of any network upgrades triggered in interconnection, with reimbursement by transmission providers over five years through payments or credits against transmission service charges.[98] A similar crediting approach could be adopted for large load customers.

[95] For a version of this argument, see the Industrial Customer Organizations joint comments in FERC RM 26-4-0000 (ICO 2025).
[96] Cost allocation issues will be determined at the final outcome of the Rule 30 proceeding (A-24-11-007).
[97] Most non-ISO transmission providers are subject to the LGIA and use the crediting policy for funding network upgrades. CAISO also uses the crediting policy, but other FERC-jurisdictional ISOs use a *but for* policy, in which network upgrade costs are allocated to generators.
[98] The LGIA allows longer repayment schedules when it is mutually agreeable, with a not-to-exceed limit of 20 years. See section 11.4.1 of the *pro forma* LGIA (FERC 2024b).

4.5.2 Large Load Tariffs (Solution Area S12)

Historically, large industrial customers often took electricity service under a general tariff with a large industrial rate class, or utilities established service rules for larger customers through special contracts developed on an *ad hoc* basis. The former approach may limit utilities' ability to set terms and conditions that are tailored to customer characteristics and risks that different kinds of customers pose to other customers and utility shareholders. The latter approach requires significant time and resources, often with high transaction costs and less transparency. To address these two limitations, many jurisdictions are developing large load rate classes, tariffs, or standard contracts with terms and conditions that are tailored to large loads.[99]

In 2025, at least one new large load tariff was proposed each month, and more than 20 states have active large load tariff proceedings.[100] The solutions in S12 (Table 20) aim to increase transparency and efficiency (S12.1, S12.2, S12.4, S12.5) and establish clear rules for how the risks of large load cost impacts will be mitigated (S12.3).

Table 20. Potential Solutions for Large Load Tariffs (Solution Area S12)

- S12.1 Clear eligibility requirements
- S12.2 Standard rates
- S12.3 Risk mitigation measures
- S12.4 Interruptible service requirements
- S12.5 Customer choice programs for large loads

S12.1 Clear eligibility requirements. Eligibility requirements establish which kinds of customers can or must take service under a tariff or rate class. Eligibility requirements are often in terms of minimum size and minimum load factor, though some jurisdictions have developed tariffs specific to the type of customer being served, such as data centers or cryptocurrency miners.[101] Table 21 shows eligibility requirements for six utilities (approved and proposed), illustrating the range of requirements across jurisdictions.

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[99] The difference between a tariff, a new rate class, and standard contracts can be subtle and jurisdiction-specific. In general, tariffs set terms and conditions for service and contain rate schedules. Rate classes — for instance, "residential" or "large commercial and industrial" — are categories of customer that are used for cost allocation. In some jurisdictions, the solutions in this section could be implemented by developing a new rate class or standard contracts for large load customers, whereas in others they would require a separate tariff. Creation of a large load rate class may be justified when large load customers are likely to have significantly different load characteristics than customers in an existing class. For example, Dominion Energy Virginia's new large load class includes all customers with contract demand above 25 MW and a load factor of at least 75% (Table 21). Costs can be allocated to customers in the large load class differently than they are for customers in existing rate classes. For instance, generation capacity costs might be allocated using an average of four monthly coincident peaks for a standard industrial customer rate class and 12 monthly coincident peaks for a large load rate class.

[100] See Frick and Lam (2025) and the Smart Electric Power Alliance's (SEPA's) Database of Emerging Large-Load Tariffs.

[101] Whether tariffs that are specific to customer types are discriminatory may be state by state. For instance, the Ohio PUC determined that AEP Ohio's data center tariff was not discriminatory because AEP Ohio provided evidence to support a reasonable basis for discrimination (OPUC 2025, paragraphs 128-129).

Table 21. Example Eligibility Requirements (Approved and Proposed)

Utility	Customer type	Minimum size (MW)	Load factor (%)
Arizona Public Service (APS) Extra High Load Factor (XHLF) Rate	Large load and data center customers	5	92%
Dominion Energy Virginia Rate Schedule GS-5: High Load/Load Factor Service	Large load customers	25	75%
East Kentucky Power Cooperative (EKPC) Rate DCP	Data center customers	15	60%
El Paso Electric Large Economic Development Service Rate (Schedule 33A) and Medium Economic Development Rate (Schedule 33B)	Data center customers	50 (33A) 0.6 (33B)	Not specified
Florida Power & Light Large Load Contract Service-1 (LLCS-1) and Large Load Contract Service-2 (LLCS-2)	Large load customers	50	85%
Grant County Public Utility District Schedule No. 17 (Evolving Industries)	Crypto-currency miners	0.2	75%
We Energies Very Large Customer (VLC) Tariff and Bespoke Resources Tariff	Large load customers	500	Not specified

Note: Tariffs for We Energies and APS were proposed at the time writing; all other tariffs and rates had been approved.

S12.2 Standard rates. Rate schedules with large load customers are often negotiated in individual electric service agreements. However, to the extent possible, setting standard rates can improve transparency and reduce transaction costs. Utilities have taken a variety approaches to rate design for large loads, with different emphasis on demand, energy, and customer charges and a range of approaches to time-differentiated and volumetrically differentiated pricing, as illustrated in the examples below.

Standard rates for large loads

El Paso Electric, Schedule 33A: Large Economic Development Service Rate
Schedule 33A is available to data center customers with more than 50 MW of billing demand.

	Summer (Jun-Sep)	Non-Summer (Oct-May)
Customer charge ($ per meter per month)	$500.00	$500.00
Demand charge ($/kW)	$13.42	$10.53
On-peak energy charge ($/kWh)	$0.15102	$0.00264
Off-peak energy charge ($/kWh)	$0.00264	$0.00264

(continued on next page)

Standard rates for large loads, continued

Grant Public Utility District, Schedule 17-B: Evolving Industry Service
Schedule 17-B is for retail customers with service of 200 kW contract or actual 15-minute demand.

Basic charge ($ per month)	$1,000.00
Demand charge ($/kW per billing period)	$28.18
Energy charge ($/kWh)	$0.00554
Monthly minimum charge ($/mo)	Demand charge × 75% of customer's maximum billing demand during most recent 12-month period

Xcel, Large General Time-of-Day Service
Large General Time-of-Day service is mandatory for retail customers having a 15-minute metered demand greater than or equal to 200 kW for at least four of 12 months.

		Summer (Jun-Sep)	Non-Summer (Oct-May)
Customer charge ($ per month)		$180.00	
On-peak demand charge ($/kW-mo)	**Secondary**	$13.00	$11.00
	Primary	$12.74	$10.78
	Transmission transformed	$11.76	$9.95
	Transmission untransformed	$11.70	$9.90
Distribution demand charge ($/kW-mo)	**Secondary**	$2.50	
	Primary	$1.50	
	Transmission transformed	$1.00	
	Transmission untransformed	$0.00	
Energy charge ($/kWh)	Secondary, on-peak	$0.08471	$0.07621
	Secondary, off-peak	$0.04982	$0.04982
Energy charge discounts	Primary	2.0%	
	Transmission transformed	9.5%	
	Transmission untransformed	10.0%	

Notes: 'transformed' refers to lower voltage transmission service; 'untransformed' refers to transfer service above 69 kV. Energy charge discounts are discounts from the secondary energy charge rate. Some customers can also opt-in to this rate schedule, with a lower customer charge but the same other rates.

Indiana Michigan Power Company (I&M), Tariff I.P.
Tariff I.P. is available to customers with monthly billing demands of 600 kW or greater.

	Secondary	Primary	Sub-transmission	Transmission
Demand charge ($/kW)	$16.474	$14.089	$10.825	$10.194
Energy charge ($/kWh), first 410 kWh	$0.05703	$0.05413	$0.05333	$0.05058
Energy charge ($/kWh), over 410 kWh	$0.01359	$0.01313	$0.01296	$0.01286
Monthly service charge ($/mo)	$180.00	$275.00	$275.00	$275.00
Minimum demand charge ($/kW)	$20.995	$18.472	$15.106	$14.700

S12.3 Risk mitigation measures. Many large load tariffs include risk mitigation measures, designed to provide utility and consumer protection. They can include: minimum contract length, exit fees, minimum billing demand, minimum load ramp rates, collateral and credit requirements, modification rules, upfront payment, refundable deposit, contribution in aid of construction, and interruptible service requirements.[102] Risk mitigation measures may need to be designed to scale with growth in large loads so that they can be efficiently and effectively implemented if the number of large load customers or the quantity of large loads increase. Often, risk mitigation measures work in tandem and can sometimes have overlapping effects, making it important to approach risk mitigation from a portfolio perspective in order to try to avoid redundancy.

The design of these risk mitigation measures differs significantly across large load tariffs.[103] Several of the recently proposed or approved large load tariffs have minimum contract lengths of 10 to 15 years with exit fees, to ensure that utilities recover any incremental fixed costs required to serve the customer.[104] While long-term contracts can improve certainty of large loads appearing and paying for new generation and grid capacity, they may do so at the cost of longer-term flexibility as LSEs and customer costs, technologies, and preferences change.[105]

Just over half of large load tariffs reviewed have a minimum billing demand requirement, typically between 75% and 90% of either contract capacity or a previous billing period. Minimum billing demand requirements are similar to take-or-pay clauses, protecting against customer demand and revenues falling short of the amount required to recover incremental sunk costs. A smaller number (around one-third) of tariffs have explicit rules for allowed ramp-up periods, which protect existing customers against slower than expected ramp-up of new large load demand. The most commonly allowed ramp is five years, though values range from one to 10 years. Longer ramp periods may result in existing customers bearing costs incurred for the large load customer during the early years unless the timing of costs matches the ramp schedule.

Most tariffs include credit and collateral requirements, including credit exemptions if the customer posts collateral. Credit requirements are often in the form of credit ratings. Collateral requirements are often tied to expected revenues over a contract term. Credit and collateral requirements are diverse, as illustrated in the examples that follow.

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[102] Some risks could also be addressed through eligibility criteria, such as minimum load or minimum load factors.

[103] All of the examples in the next two paragraphs draw on SEPA's Database of Emerging Large-Load Tariffs. At the time of writing, the database had 66 large load tariffs or rates (last accessed in November 2025).

[104] Examples include Duke Energy Florida's proposed large load tariff (15-year minimum with exit fees), I&M's approved Tariff LP (12-year minimum with exit fees), and Consumers Energy's proposed Rate GPD (15-year minimum with exit fees).

[105] One solution to reducing long-term contract risk could be to include an option for large load customers to request partial or full termination of contract obligations if the utility finds that it can avoid costs by doing so.

Collateral, credit, and deposit requirements in large load tariffs

AEP Ohio's Data Center Tariff requires data center customers to have a credit rating of at least A- from S&P Global and A3 from Moody's Corporation, and cash or cash equivalents on an audited balance sheet greater than 10 times the collateral requirement. Otherwise, when signing the contract, the customer must provide a guarantee or collateral equal to 50% of the total minimum charges for the full term.

Under Black Hills Energy's Large Power Contract Service, customers may be required to provide a deposit or credit support such as a performance guarantee or letter of credit. This credit support will be held as security for payment of obligations incurred on behalf of the customer.

I&M's Tariff LP requires customers to have at least one of the following: (1) a guarantee from the customer's ultimate parent or a corporate affiliate for the collateral requirement, as long as the guarantor meets a minimum credit rating and liquidity; (2) a letter of credit indicating a credit rating of at least A- from S&P and A3 from Moody's; or (3) cash for the collateral requirement. Other collateral requirement exemptions exist for customers with minimum ratings.

The collateral requirement for large loads in Consumers Energy's proposed Rate GPD is 50% of the total minimum monthly charges multiplied by the number of months remaining on the contract, recalculated annually.

Some tariffs have an option that allows large load customers to modify their contracted capacity at some point during the term of the contract. Clear guidelines on capacity modifications can be a risk mitigation measure for customers and, by setting clear expectations on the conditions under which customers will be allowed to modify their contracts, for utilities as well. Examples include I&M's Tariff I.P., which allows large load customers to reduce contract capacity by up to 20% at any point after the first five years of the contract, and AEP Ohio's Data Center Tariff, which allows modifications to contracted capacity three years prior to the requested modification date and three years prior to the end of the contract.

S12.4 Interruptible service requirements. Large load tariffs may have terms that allow utilities to interrupt service during periods of system stress.[106] Some utilities require large loads to take service under a tariff with interruptible service requirements. In other cases, these tariffs are opt-in and more akin to demand response programs. Interruptible tariffs can provide additional operational flexibility to utilities and avoid impacts on other customers, particularly when large loads are a significant share of a utility's total load.

Interruptible service requirements typically specify the maximum number of interruptions (events), the maximum duration of each interruption, and the number of hours before the interruption that the utility will notify the customer. In some cases, the tariff will also provide compensation for service interruptions, whereas in other cases incentives may be in the form of

[106] 'Interruptible service' here could refer to a range of arrangements, including those in which (a) the utility is able to remotely control the customer's load, (b) the utility sends instructions to customers with penalties for non-performance, or (c) the utility sends instructions to customers and customers are paid for performance, with limited to no penalties for non-performance.

demand charge reductions or opportunity for faster interconnection. Tariffs are often less clear on penalties for non-compliance, if service interruption is controlled by the customer rather than the LSE. Interruptible service requirements in retail tariffs are typically different from, but could be aligned with, the wholesale curtailment services in solution areas S4 (Section 4.2.2) and S5 (Section 4.2.3) and flexible interconnection for the distribution system in S6 (Section 4.2.4).[107]

Interruptible service requirements in large load tariffs

Idaho Power's Speculative High Density Load Tariff

- Applicable to customers whose metered usage exceeds 2,000 kWh per billing period but mandatory for customers have metered demand of 1 MW or more per billing period for two or more periods during the most recent 12 periods
- Requires that customers be able to be remotely disconnected
- Up to 10 interruptions for up to 225 hours annually, with a maximum interruption of 10 hours per event
- Interruptions are limited to 13:00–23:00, Monday through Friday, June 15 to September 15
- Customers are compensated $0.0451–$0.0453 per kW of reduction per event hour, depending on customer size and rates

Entergy Arkansas' Large Power High Load Density Service

- Required for customers engaged in cryptocurrency mining
- Customer specifies firm contract demand (≤ 10% of contracted demand) that will be excluded from interruptions
- Customer can choose from two options for non-firm demand: (1) Option A, which has 10 maximum interruptions per year, maximum four hours per interruption, and a more than one-hour notice time; (2) Option B, which has 10 maximum interruptions per year with a more than one-hour notice time, 20 maximum interruptions per year with a more than 30-minute notice time, and a maximum of four hours per interruption
- Compensation for interruptions are embedded in the demand charges: $16.96/kW for firm demand, $11.64/kW for Option A non-firm demand, and $9.70/kW for Option B non-firm demand
- Entergy Arkansas may register customers taking this service as demand response resources in MISO's RA program

S12.5 Customer choice programs for large loads. Some large load customers have corporate energy goals that require procurement of renewable energy or other non-emitting energy sources. In jurisdictions that do not allow customers to choose their suppliers, utilities may help customers to meet these goals by procuring renewable or non-emitting generation on their behalf. However, individually tailored arrangements may be a less efficient way to provide customer choice services to large loads, relative to offerings that have standardized terms and conditions. To address this issue, several jurisdictions have begun to develop standardized tariffs, schedules, and riders for large loads that support customer choice.

[107] See solution area S5, Section 4.2.3 for more discussion on the differences between wholesale curtailable load services and more traditional demand response.

Customer choice tariffs, schedules, and riders for large loads

Nevada Energy's Clean Transition Tariff
Nevada Energy's (NVE's) Clean Transition Tariff (CTT) allows customers with an annual average hourly load of 5 MW or more to enter into a supply contract with NVE for energy resources that have been developed for the load, with a contract equal to lifetime of the generating facility, any premium above NVE's average expected supplied costs paid for by the customer, and customer ownership of clean energy credits. The CTT is effectively a wholesale contract with a retail provider that holds NVE's native customers harmless. The first project developed through the CTT will be NVE's 115 MW advanced geothermal contract with Fervo Energy on behalf of Google.[108]

Dominion Energy's Schedule CFG: Carbon-Free or Renewable Generation Supply Service (Experimental)
Dominion Energy's Schedule CFG is a companion to its non-residential tariffs and allows non-residential customers to procure carbon-free or renewable generation through the utility. Customers taking service under Schedule CFG pay for electric service under the applicable tariff and then separately pay Schedule CFG charges. These charges include an administrative fee of $500 per 30-day billing period and any net charge from operating the specified resource in the PJM market. Dominion Energy will retire any renewable energy credits (RECs) on customers' behalf.

Duke Energy's Green Source Advantage (GSA) Program
Under the GSA Program, customers with at least 1 MW of annual peak demand in one location or 5 MW in multiple locations can identify their own renewable energy supplier and negotiate contractual terms and conditions with that supplier. Duke then buys energy from the supplier through a power purchase agreement (PPA) and charges the customer for PPA costs and administrative fees.

Evergy Kansas' Clean Energy Rider
Evergy's Clean Energy Rider (CER) is available to customers that receive service under the utility's Large Load Power Service schedule. Under the CER, Evergy will develop a clean energy resource plan with the customer through its IRP process, subject to Kansas Corporation Commission review and approval. The customer will be responsible for any administrative, investment, and operating costs associated with the generating facilities over their expected lifetime. RECs will be addressed in individual contracts.

4.5.3 Wholesale Rates and Access for Large Loads (Solution Area S13)

Wholesale electricity rates and access can provide additional flexibility and risk mitigation for managing large loads, by isolating the generation costs of large loads from other customers. There are different approaches to wholesale rates, varying in the degree to which regulated utilities continue to provide retail service.

[108] For more background on the CTT and this project, see _Latitude Media, "The 'clean transition tariff' won approval in Nevada. What's next for Fervo?" May 15, 2025.

The two solutions in S13 shift large loads to wholesale rates, either with the utility continuing to provide retail service (S13.1) or by allowing large load customers to choose their own generation capacity and energy suppliers through direct access (S13.2).

Table 22. Potential Solutions for Wholesale Rates and Access (Solution Area S13)

- S13.1 Wholesale rates under utility service
- S13.2 Direct access programs

S13.1 Wholesale rates under utility service. Utilities can form unregulated wholesale generation companies to serve large load customers, with the customer buying power through the regulated utility. These arrangements reduce stranded cost risks for existing customers by shifting fixed cost recovery risks to unregulated wholesale companies and large loads, but they may also introduce competition concerns and additional risks for the regulated arm of the utility.

Utilities can also offer wholesale rates that include market-based generation energy, ancillary services, capacity charges, and unbundled transmission and distribution rates. Market-based wholesale rates can isolate large load customers by separately procuring the capacity, energy, and ancillary services needed to serve them and applying a “higher of” principle, though existing customers will likely take on some risk because of the difficulty of matching the amount and timing of customer capacity needs.

Wholesale versus retail rates and service

Wholesale and retail service are a spectrum rather than two discrete categories, ranging from bundled retail service (full retail) to direct access (full wholesale). In between are wholesale rates that are offered by regulated utilities.

Under bundled retail service, customers pay energy and demand charges that “bundle” generation, transmission, and, if applicable, distribution costs. In direct access programs, customers secure their own generation capacity and energy and pay wholesale (unbundled) transmission and distribution costs. In between bundled retail and direct access, customers pay generation rates that are based on wholesale energy, ancillary services, and capacity costs. They pay unbundled transmission and, if applicable, distribution rates that are based on open access rates.

S13.2 Direct access programs. An alternative to the utility-managed approaches in S13.1 is to allow for limited or full direct access, enabling large loads to choose their suppliers and pay wholesale rates for transmission and, where applicable, distribution. A small number of states — for instance Michigan, Oregon, and Virginia — have direct access programs that are limited to larger customers, with no retail competition allowed outside of these programs.[109] Direct access programs can address concerns around wholesale competition and stranded costs, though they result in some loss of state regulatory control and likely require enabling legislation.

Wholesale rates under retail service

Northern Indiana Public Service Company's (NIPSCO's) GenCo model
In 2025, NIPSCO received approval from the Indiana Utility Regulatory Commission to create an unregulated wholesale generation company ("GenCo") that will provide wholesale service to NIPSCO on behalf of large loads. NIPSCO will continue to be the retail provider for the large loads, but the new generation assets to serve these loads will be owned by GenCo rather than NIPSCO. NIPSCO will pay GenCo through a PPA that is intended to isolate the costs of new generation assets from existing customers. The extent to which costs will be isolated will depend on the terms of the PPA and NIPSCO's retail contracts with large loads.

Evergy Missouri's Special High Load Factor Market Rate (Schedule MKT)
Evergy's Schedule MKT is a retail rate that mimics wholesale pricing. The energy charge portion of the MKT rate is based on an SPP hourly day-ahead market price (locational marginal price) at a specified load node. The generation capacity charge portion of the rate is based on wholesale capacity costs. The pricing terms are limited to no more than five years, and contracts cannot exceed 10 years. Evergy is required to periodically determine whether the incremental costs to service Schedule MKT customers exceed the amount that it recovers from these customers and, if so, to recover any revenue shortfalls so that other customers are held harmless. Schedule MKT is available to customers with over 100 MW in monthly demand (or 150 MW within five years) with a minimum annual load factor of 0.85 or greater.

[109] Michigan's Electric Customer Choice program also allows customers to choose suppliers, subject to a cap equivalent to 10% of utility sales that has been reached for most utilities; see https://www.michigan.gov/mpsc/consumer/electricity/choice. For more on Oregon's Direct Access program, see https://www.oregon.gov/puc/utilities/pages/direct-access.aspx. For more on Virginia's Energy Choice program, see https://www.dominionenergy.com/virginia/rates-and-tariffs/energy-choice.

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