RAP
REGULATORY
ASSISTANCE PROJECT

November 2026

Data Centers and Electricity Rates: Improving Cost Allocation and Protecting Customers

Part of the series *Data Centers and the Next Era of Energy Regulation*

Mark LeBel, Louisa Eberle, Joshua Ryor and Alexander Urquhart,
Regulatory Assistance Project

Dr. Fredrich (Fritz) Kahrl, 3rdRail



Acknowledgments

The authors would like to thank Natalie Mims Frick from the Lawrence Berkeley National Laboratory for contributions to this effort and our colleagues Emily Bosch, Will Fridlund, Carl Linvill, and Andrew Valainis for their support in drafting and editing this report. We would also like to acknowledge and express appreciation to the following people who provided helpful insights into earlier drafts of this paper:

Peter Cappers, Lawrence Berkeley National Laboratory

Jim Lazar, Moderator, Electricity Brain Trust

Megan Decker, Staircase Advisory

That said, responsibility for the information and views set out herein lies entirely with the authors.

Contents

Executive Summary....i
I. Introduction....1
II. Background on the Electric System and Modern Regulatory Frameworks....4
A. The Electric System and Load Interconnection....5
B. Regulatory Frameworks and Key Cases....7
III. Cost Allocation Concepts in Ratemaking....12
A. Retail Cost Allocation under Traditional Ratemaking....13
B. Wholesale Transmission Cost Allocation....17
C. Retail Supply Choice Frameworks....18
IV. The Full Picture of Costs and Revenues from Data Center Load Growth....19
A. Costs Caused by Data Center Customers....20
B. Ratepayer Risks from Market Price Impacts and Stranded Costs....23
C. Life Cycle of Financial Contributions from Data Centers....27
D. Cost Allocation Levers Across Key Regulatory Cases....31
V. Practical Reforms to Consider....36
A. Initial Fees and Deposits....38
B. Updated Contribution in Aid of Construction Policies....39
C. Rates and Contract Structures for Large Loads....41
D. Improved Wholesale Transmission Cost Allocation and Pricing....49
E. Options for Retail Energy Supply in Fully Restructured Jurisdictions....52
F. Reallocation of Public Policy Costs....55
G. Exit Fees....56
VI. Conclusion and Further Research....59
Appendix A. Modern Regulatory Frameworks across the United States....61

List of Figures and Tables

Figure ES-1. Categories of Financial Contributions and Electricity Costs.....ii
Figure 1. Evolution of Electric Load Growth Since 1950 and Drivers of Projections Through 2030.....1
Figure 2. Illustrative Electric System.....5
Table 1. Examples of Transmission- and Distribution-Level Load Interconnection Parameters.....6
Figure 3. Four Categories of Transmission Upgrades Potentially Necessary for Interconnection.....7
Figure 4. Spectrum of Electric Regulatory Frameworks in the United States.....8
Figure 5. Simplified Vertically Integrated Electric Utility Ratemaking Steps.....14
Figure 6. Full Life Cycle of Financial Contributions from Data Centers.....28
Figure 7. Categories of Financial Contributions and Electricity Costs.....31
Figure 8. Simplified Cost Allocation Structure for Vertically Integrated Non-RTO Utilities.....33
Figure 9. Simplified Cost Allocation Structure for Vertically Integrated Utilities with RTO Membership.....34
Figure 10. Simplified Cost Allocation Structure for Fully Restructured Jurisdictions.....35
Figure A-1. States with Major Vertically Integrated Non-RTO Investor-Owned Utilities. 62
Figure A-2. Regional Transmission Organizations / Independent System Operators….64
Figure A-3. Electric Supply Choice Map.....66

Executive Summary

Every level of government is concerned that data centers may impact electricity rates, now or in the future. Major technology companies signed the Ratepayer Protection Pledge at the White House in March 2026. Many states adopted their own version of a pledge, and state utility commissions are addressing these issues in litigated proceedings. Local governments across the country are now closely scrutinizing data center proposals that they used to compete to attract.

People everywhere are concerned for good reasons, but the impacts will vary by location and time. Data centers are likely driving up rates for some customers, notably residential customers on default supply rates in New Jersey, Pennsylvania and Illinois, but utility analysis suggests data centers may be driving down rates in other places, like Indiana. This report unpacks the complexity behind these electricity rate impacts and cost allocation issues, which depend significantly on the industry structure and regulatory framework in each jurisdiction. Understanding these structures and frameworks is the first step toward identifying necessary changes to protect customers.

In an environment where the costs caused by data center load growth are higher than the existing rates and charges that data centers pay, load growth from data centers puts upward pressure on rates. Analysts should consider the *full life cycle of revenue* from data centers, including the timing of payments, because up-front contributions can be banked, and later ones have more risk. For traditionally regulated utility costs, regulators have the authority to determine the allocation of costs across the customer base and can change existing practices to ensure that the revenue from data centers covers the costs caused by data centers. In states with vertically integrated utilities, this includes generation supply costs, but regulators in fully restructured jurisdictions no longer have access to some of the traditional cost allocation tools for retail generation supply rates.

The next layer of analysis requires understanding how increased demand causes higher wholesale electricity market prices, how these wholesale prices influence retail rates under different regulatory frameworks and the steps that can be taken to mitigate wholesale price increases. Default generation supply rates in fully restructured jurisdictions have been primarily based on short-term contracting, so wholesale price increases get fully passed through to residential customers. In other jurisdictions, vertically integrated utilities tend to be hedged, particularly in the near term, against market price increases due to load growth. However, ratepayers under a vertically integrated utility take on the risk of overly costly generation investment, in general, as well as stranded costs and above-market contracts. In either regulatory framework, new investments in supply, whether procured specifically by data center customers or not, also help mitigate electricity market price increases, but ratepayers do pay for any traditionally regulated investments.

Figure ES-1. Categories of Financial Contributions and Electricity Costs

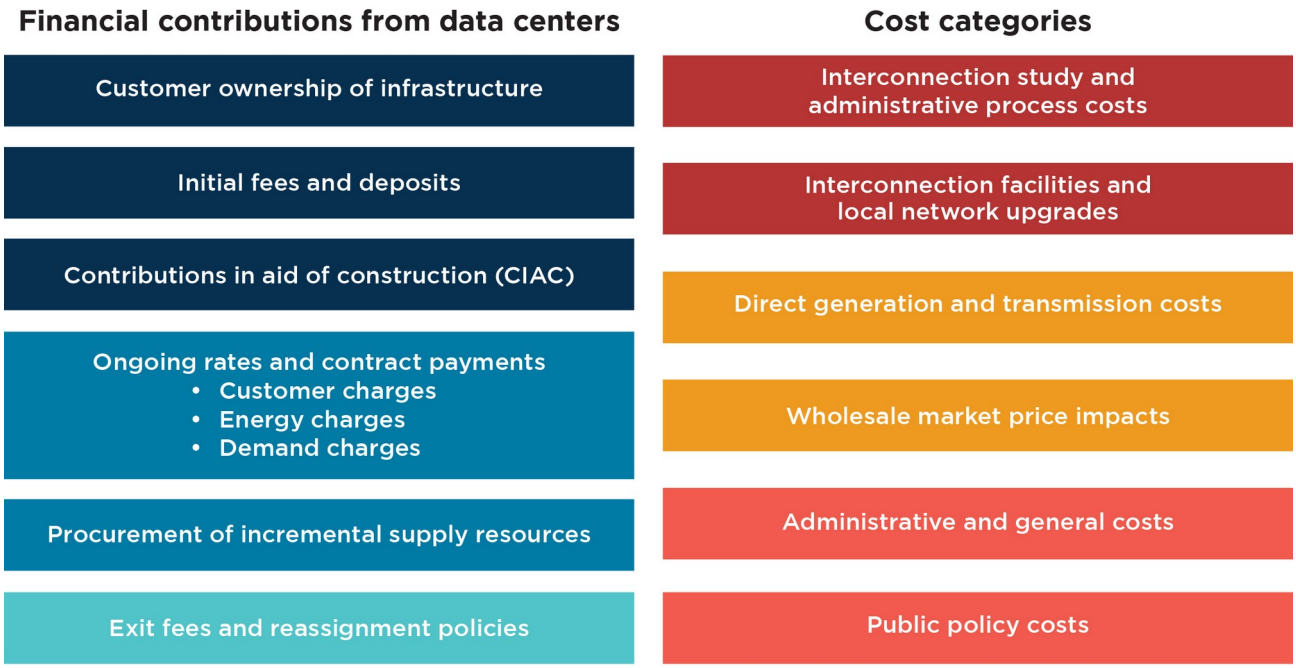


Figure ES-1 above presents both the revenue and cost sides of the equation. The left side shows the categories of *potential* financial contributions from data centers. This spans the *full life cycle* of a data center customer, from initial inquiries to service termination:

- In dark blue, there are payments that begin before data center operation, including customer ownership of certain infrastructure, initial fees and deposits and any contributions in aid of construction (CIAC).
- In medium blue, there are ongoing rates and contract payments that constitute routine bills paid by data center customers. In addition, there may be arrangements for customer procurement of incremental supply resources. Incremental supply procurement can be a method to mitigate wholesale market price increases.
- In light blue, there are any exit fees paid by data center customers at the termination of service as well as the possibility that the customers' financial responsibilities are reassigned to another large customer.

If these financial contributions from data centers across their life cycle fully cover the costs incurred by data centers, then other customers will be protected from paying costs incurred by data center development.

The right-hand side of figure ES-1 shows the different cost categories that data center customers cause and can contribute to. A key distinction across cost categories is the degree to which they are attributed to specific customers or sources of load growth.

- At the top, in dark red, are costs that are driven by a specific customer or set of customers: interconnection studies and administrative process costs and interconnection facilities and local network upgrades.
- In orange, traditionally regulated generation and transmission costs and wholesale market price impacts that are due to load growth *generally* but not attributable to any specific subset of customers.
- In light red, administrative and general costs caused by all utility customers, as well as public policy initiative costs, such as low-income support and energy efficiency and weatherization programs.

To protect customers, regulatory agencies need to determine necessary policy changes, which may require supportive legislation in some cases. This report examines seven categories of reforms that the Federal Energy Regulatory Commission (FERC) and retail regulators are already implementing to address rate pressure from data centers:

- Initial fees and deposits
- Updated contribution in aid of construction policies
- Rates and contract structures for large loads
- Improved wholesale transmission cost allocation and pricing
- Options for retail energy supply in fully restructured jurisdictions
- Reallocation of public policy costs
- Exit fees

Many concepts described throughout this report can be the subject of further exploration and establishment of best practices. More generally, six areas particularly warrant further research in this new era of load growth:

- How can states and regions improve their understanding of the marginal or incremental costs of load growth?
- How can FERC and states clarify any areas of jurisdictional ambiguity and promote appropriate coordination across RTO/ISOs (regional transmission organizations/independent system operators) and state utility commissions?
- What complementary strategies should FERC, RTOs/ISOs and states implement to promote and expedite development of electricity supply? What are best practices for “bring your own new generation” and “bring your own new clean energy”?
- What are new models for pricing interconnection, transmission and resource adequacy for colocated load and generation balance efficiency and fairness?
- What kinds of planning and load forecasting improvements would help to better manage large load rate impacts, and which entities are best suited to motivate and oversee these improvements?

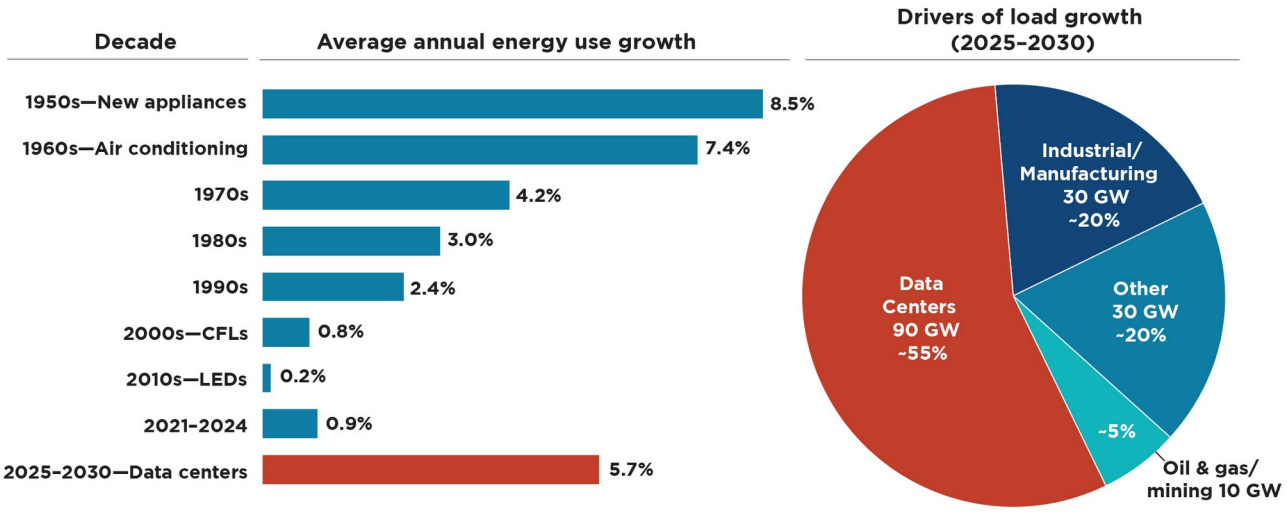
- How should jurisdictions protect against end-of-life-cycle concerns about financial solvency and more complex corporate structures?

Tackling these big picture questions will protect ratepayers while also laying the foundation for a 21st-century regulatory system.

I. Introduction

New developments are challenging our existing regulatory models. Across the United States, we see growth in electricity usage not seen since the 1960s. A significant portion of current and projected load growth is from data centers, which have unique characteristics compared to past forms of industrial load growth. Both a historical comparison and a forward-looking projection are shown in Figure 1.

Figure 1. Evolution of Electric Load Growth Since 1950 and Drivers of Projections Through 2030



Source: Adapted from Wilson, J. D., Meyer, S., Zimmerman, Z., & Gramlich, R. (2025, November). *Power demand forecasts revised up for third year running, led by data centers*. Grid Strategies. https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf[1]

Aluminum smelters and petroleum refineries frequently have demand in the hundreds of megawatts (MW), but even these large industrial customers are modest in scale compared to current proposals for multi-gigawatt (GW) data centers. Data centers have also tended to cluster in specific regions and insist on connecting to the electric system as quickly as possible because of technology companies' needs and business models. Data centers also have unique impacts on electric system stability and reliability, due to their size and ramp rates.[2]

Recent public and regulatory discourse has heavily focused on concerns that utilities' costs to serve data centers will raise rates for existing ratepayers — including households and

[1] As reproduced in Mai, T., Lew, D., Silverstein, A., Ela, E., Matevosyan, J., Okullo, J., Shattuck, A., & Frick, N. M. (2026, March). *Historical and modern large loads* [White paper]. Energy Systems Integration Group. https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Historical-vs-Modern-Large-Loads-white-paper-2026.pdf

[2] North American Electric Reliability Corporation. (2026, May 4). *Essential action to industry.* https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf

small businesses. Some government studies,[3] utilities[4] and analysis sponsored by data center companies[5] report that data centers have lowered household electricity costs to date, but strong evidence suggests that data centers are already increasing costs for other ratepayers in at least one region of the country: specific parts of PJM Interconnection, including New Jersey, Pennsylvania, Delaware, Maryland, Ohio, northern Illinois and Washington, D.C.[6] Concerns about potential cost increases, combined with broader angst about the societal impacts of artificial intelligence, raise data centers' political profile and contribute to public opposition.[7]

The actual impact of data centers on electricity rates varies from place to place and over time. In principle, new customers and other forms of load growth can lead to either increased or decreased rates for other customers.[8] Generally, this depends on the relationship between the impact of the new load on the electricity system, the resulting costs and the amount of revenue the new load contributes.[9] Analysis of new customer revenue sometimes focuses on monthly or annual electricity bills but should be considered in a *full life-cycle manner* — starting with any initial fees and deposits and ending with any exit fees and reassignment policies.

In the current environment, it is reasonable to be concerned that new costs incurred due to data-center-driven load growth may be higher than the revenues that would come from applying existing industrial rates to new data center customers. In the best-case scenario, data centers would improve the utilization of existing grid infrastructure, and the financial contributions from data centers would reduce the costs for that infrastructure paid by existing ratepayers. But given the scale of the aggregate build-out in many regions, it seems more likely that large data center load growth will require major new infrastructure

---

[3] A 2024 Virginia legislative report concluded that although data centers are mostly paying their full cost of service, future cost increases for nondata center customers are likely because "current utility rate structures are not designed to account for sudden, large cost increases from the construction of new infrastructure to serve a relatively small number of very large customers." Joint Legislative Audit & Review Commission. (2023). *Data centers in Virginia.* https://jlarc.virginia.gov/landing-2024-data-centers-in-virginia.asp

[4] Penrod, E. (2026, February 17). *Data center growth has helped PG&E cut rates 11% since 2024 CEO says.* Utility Dive. https://www.utilitydive.com/news/data-center-growth-has-helped-pge-cut-rates-11-since-2024-ceo-says/812230/; and NIPSCO. (2026, October 28). *NIPSCO to deliver $57.5 million in savings to electric customers from data center development* [Press release]. https://www.nipsco.com/our-company/news-room/news-article/nipsco-to-deliver--57.5-million-in-savings-to-electric-customers---from-data-center-development

[5] Riu, I., Kishal, P., Mettetal, L., Santoni-Colvin, M., Platter, H., Greszczuk, S., Cardona, J., Bertrand, L., Spencer, S., & Ramirez, S. (2025). *Tailored for scale: Designing electric rates and tariffs for large loads*. Energy and Environmental Economics (E3). https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

[6] DeCourcey, M., & Saraswat, M. (2026, February 2). *Retail rate trends in the US.* Charles River Associates. https://media.crai.com/wp-content/uploads/2026/02/02092628/Retail-rate-trends-in-the-US.pdf. In addition, the Union of Concerned Scientists contends that data centers have caused $4.3 billion in transmission infrastructure upgrades that are being charged broadly to ratepayers in the PJM region. Union of Concerned Scientists. (2025, September). *Connection costs* [Policy brief]. https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20-%20Sep%202025.pdf

[7] Jones, J. (2026, May 13). *Americans oppose AI data centers in their area.* Gallup. https://news.gallup.com/poll/709772/americans-oppose-data-centers-area.aspx.

[8] See, for example, O'Shaughnessy, E., Wiser, R., Cappers, P., Deason, J., Frick, N. M., & Hledik, R. (2026, July 15). Revisiting the relationship between demand growth and electricity prices. *Joule, 10*(7). https://www.sciencedirect.com/science/article/abs/pii/S2542435126002126

[9] Riu et al., 2025 and Lam, L., R. Hledik, and N. Northrup. 2026. "Impacts of Large Loads on Electricity Rates: A Primer." Energy Systems Integration Group. https://www.esig.energy/reports-briefs/rate-impacts-of-large-loads-primer.

investments.[10] Electric equipment costs have been rising quickly since 2020,[11] which means that building new infrastructure will likely be more expensive than the existing infrastructure already included in current rates. If the new higher cost infrastructure is shared across all ratepayers, then existing rates tend to increase. In addition, data center load growth puts upward pressure on wholesale electricity market prices.[12] Combining different types of impacts, a recent econometric study from the MIT Center for Energy and Environmental Policy Research concludes that data center entry to date has led to retail price increases for other customers, particularly customers of investor-owned utilities in restructured jurisdictions.[13] Lastly, in some jurisdictions, core cost allocation methods haven't been revisited since the 1980s or 2000s. It makes sense to re-evaluate core cost allocation methods in light of today's technology, data and regulatory context.

Policymakers at the state and federal level have started acting to reshape data center customer rates and reform related policy areas. The term "cost allocation" is frequently used to discuss these issues, but it is important to understand that this term can be used narrowly or broadly. Cost allocation in the narrower sense refers specifically to a set of regulatory mechanisms that determine the share of costs different customers pay for electric utility bills to cover electric system costs and public policy programs. RAP has written extensively about electric utility cost allocation, notably *Electric Cost Allocation for a New Era: A Manual*.[14] In the modern electricity system, however, wholesale electricity markets and retail supply choice policies have a stronger influence on customer retail rates in many parts of the United States than in the 20th century. The broader sense of cost allocation can capture a broader suite of policies that impact household and business electricity rates as well as the tools available to mitigate rate impacts from data center load growth on those existing customers.[15]

[10] Utilities, regulators and other policymakers should make improvements to planning processes to lower the cost of new infrastructure for load growth, but that is not the focus of this report.

[11] Federal Reserve Bank of St. Louis. (updated monthly). *Producer price index by industry: Electrical equipment manufacturing.* https://fred.stlouisfed.org/series/PCU3353133531

[12] Kay, O., Reaser, R., & Taylor, R. (2026, October). *Processing power: The effect of data centers on wholesale electricity markets* (Working Paper 2606). Federal Reserve Bank of Dallas. https://www.dallasfed.org/research/papers/2026/wp2606

[13] Meeks, R., Pless, J., Qi, Z., & Wang, Z. (2026, June). *Who pays for growth? Evidence from data centers and the grid.* https://ceepr.mit.edu/workingpaper/who-pays-for-growth-evidence-from-datacenters-and-the-grid/

[14] Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (2020, January). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[15] This report does not address in detail the pressure that the data center boom is putting on the broader economy. Even if islanded from the grid, data center construction and operation may be significant enough to impact a range of markets, from electric equipment and energy commodity prices to construction equipment and even interest rates.

This report develops a comprehensive framework for understanding the full array of cost allocation issues related to data centers, as well as options for limiting rate impacts on other customers.[16] Differences in regional market structures and state regulation change how data center load growth impacts other customers, as well as the tools currently available to address impacts on other ratepayers.[17] As a result, we distinguish between different market and regulatory structures. The remainder of the report is organized as follows:

- Section II explains data center interconnections to the electric system, and then key aspects of modern regulatory frameworks.
- Section III provides an overview of cost allocation concepts across three different ratemaking paradigms: traditional retail ratemaking, wholesale transmission ratemaking and retail supply choice structures.
- Section IV examines data center load growth's cost impacts in more detail, how costs and risks borne by ratepayers differ by regulatory framework, the full life cycle of revenue contributions from data centers and a comprehensive overview of leverage points to shape cost allocation for data centers.
- Section V reviews recently implemented and currently debated examples of reforms across the country.
- Section VI concludes with a description of key issues for further research.

II. Background on the Electric System and Modern Regulatory Frameworks

Understanding cost allocation levers and their limitations with respect to data centers requires understanding electric system and regulatory fundamentals. Thousands of private and publicly owned entities comprise the modern electric system in the United States.[18] Nearly all customers, large or small, connect to the network of an investor-owned utility, municipal or state-owned utility, public utility district or a customer-owned cooperative (co-op). State public utility commissions oversee investor-owned utilities, but different governance structures guide most government-owned utilities, public utility districts and co-

[16] These issues have been addressed broadly in previous publications by RAP and Lawrence Berkeley National Lab. In RAP's first installment of *Data Centers and the Next Era of Energy Regulation* in January 2026, we laid out the building blocks for utility commission regulation of data centers. Eberle, L., & Kadoch, C. (2026, February 4). *Building resilient foundations for large loads.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/building-resilient-foundations-for-large-loads/. In June 2026, Lawrence Berkeley National Lab published a review of measures necessary to accelerate the interconnection of large loads. Kahrl, F., & Frick, N. M. (2026, June). *Speed to power: Solutions for accelerating large load connections*. Energy Markets & Planning, Berkeley Lab. https://emp.lbl.gov/publications/speed-power-solutions-accelerating

[17] ESIG recently released analysis of selected measures to address large load rate impacts across several different regulatory frameworks. Energy Systems Integration Group. 2026. Impacts of Large Loads on Electricity Rates: A Quantitative Assessment. A report by the ESIG Large Loads Rate Impacts Task Force. https://www.esig.energy/reports-briefs/rate-impacts-of-large-loads-quantitative-assessment/

[18] See Lazar, J. (2016). *Electricity regulation in the US: A guide*, 2nd ed., pp. 11-24. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pdf; and U.S. Energy Information Administration. (2019, August 15). *Investor-owned utilities served 72% of U.S. electricity customers in 2017*. https://www.eia.gov/todayinenergy/detail.php?id=40913

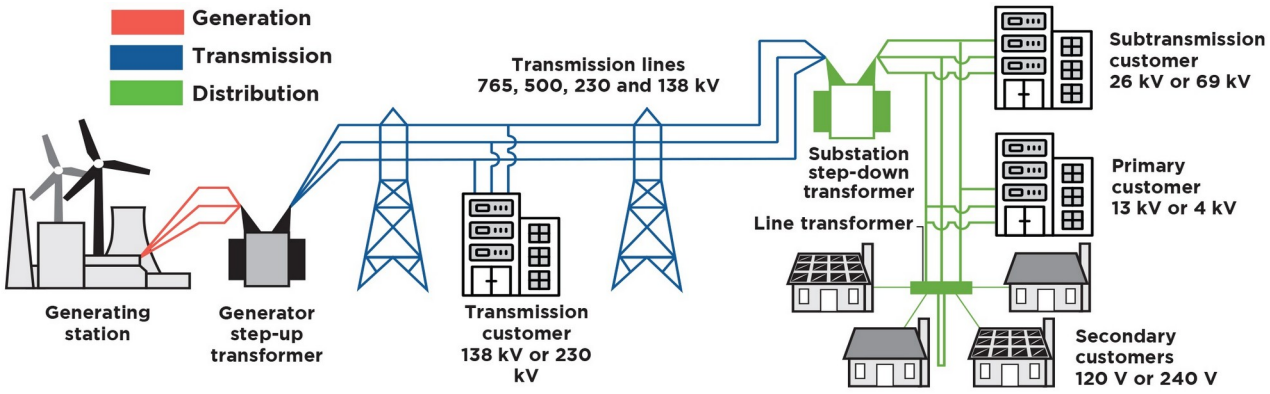
ops. The Federal Energy Regulatory Commission (FERC) oversees wholesale transmission rates and wholesale sales in interstate commerce.[19] However, the modern electric system now includes a broader universe of independent generation resource owners, investor-owned transmission entities, retail electricity supply providers and RTO/ISOs. Their relative importance depends on the region and regulatory framework.

Because the combinations of entity types and different participants in the provision of service to customers are difficult to cover comprehensively, it is helpful to simplify with an initial understanding of the components of the electric system and how data centers are connected to the system before turning to an overview of relevant regulatory frameworks. Additional details on regulatory frameworks across the United States are presented in Appendix A.

A. The Electric System and Load Interconnection

Figure 2 below illustrates a simplified version of the electric system, from large central generation facilities to small customers connected to the secondary voltage distribution system. The electric system is categorized into three separate functions: (1) generation resources, (2) high-voltage transmission lines and (3) the local distribution network.

Figure 2. Illustrative Electric System



Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*

While the entire system must be designed to provide reliable service at reasonable prices, distinctions between the portions of the electric system are relevant for different engineering and regulatory purposes. Regulatory distinctions are discussed later in this section. From an engineering perspective, higher voltage transmission lines have greater carrying capacity and lower lines losses but require additional physical space and system protection. These lines are only used to carry large amounts of power over longer

[19] The exceptions are geographically and electrically isolated areas like Hawaii, Alaska and the ERCOT region of Texas.

distances, justifying the additional infrastructure costs. Lower-voltage transmission lines are referred to as subtransmission. The distribution lines that run along streets in neighborhoods and cities are called primary voltage, and many commercial and smaller industrial customers connect directly to this portion of the network. Small end-use customers, such as single-family homes, use power at lower voltages, so the system must deliver power at a lower level, called secondary voltage.

Each customer, or a building that contains multiple customers, like an apartment or office building, must connect to the grid with its own service line. New large data centers typically connect at the transmission voltage level because higher voltages enable higher levels of energy delivery. Smaller data centers may connect to subtransmission or primary voltage distribution infrastructure. Key parameters for load interconnection are shown in Table 1 below.

Table 1. Examples of Transmission- and Distribution-Level Load Interconnection Parameters

Aspect	Transmission	Sub-Transmission	Distribution
Voltage level*	69 kV or higher	34.5 to 69 kV	4 to 34.5 kV
Load Size	Usually 20 MW or larger industrial facilities	Approximately 10 to 30 MW and includes large industrial plants, data centers, and other large regional loads	Typically less than 10 MW; often commercial, institutional, or light industrial loads

* These are not standard voltage definitions but are intended to provide general examples of voltage cut-offs between these parts of the electricity grid.

Source: Thomas, K., & Matevosyan, J. (2026, June). *Interconnection Processes for Large Loads*, p. 36. ESIG. https://www.esig.energy/wp-content/uploads/2026/06/ESIG-Large-Loads-Interconnection-Process-report-2026a.pdf

To connect to the transmission or distribution system, data centers and utilities need to invest in different kinds of infrastructure. In regulatory filings in California, PG&E (Pacific Gas and Electric) described four categories of potential infrastructure investments necessary to interconnect a data center to the transmission system:[20]

- **Type 1:** Transmission Service Facilities. These new transmission facilities are dedicated to providing service to the large load customers only.
- **Type 2:** Transmission Interconnection Upgrades. These are substation or switching station facilities that could be new transmission facilities connecting the transmission network to large load facilities.

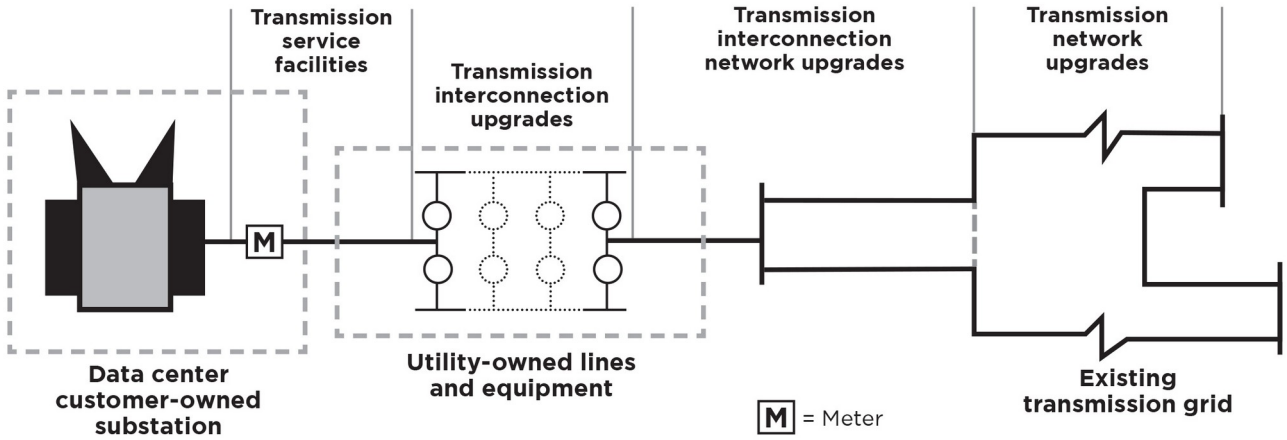
[20] Public Utilities Commission of the State of California, Decision partly granting and partly denying PG&E Company's motion for interim implementation of Electric Rule Number 30, Decision 25-07-039, July 24, 2025, p. 8. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M574/K875/574875643.PDF

- **Type 3:** Transmission Interconnection Network Upgrades. These are modifications to adapt the PG&E transmission network to provide service to the large load customers.

- **Type 4:** Transmission Network Upgrades. These are modifications to the existing transmission grid to integrate service to the large load customers. PG&E describes the need to adapt an existing transmission asset to large customers.[21]

These four types of infrastructure are diagrammed in Figure 3 below.

Figure 3. Four Categories of Transmission Upgrades Potentially Necessary for Interconnection



Source: Adapted from PG&E graphic in CA PUC, *Decision Partly Granting and Partly Denying PG&E Company's Motion for Interim Implementation of Electric Rule Number 30*, Decision 25-07-039, July 24, 2025, p. 9. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M574/K875/574875643.PDF

Note that the diagram also shows a "data center customer-owned substation" on the left-hand side. In principle, this could be owned by the utility or the customer. The M symbol shows the utility meter and denotes the boundary between utility-owned and customer-owned assets. If the utility owned the substation, the meter would move to the customer side of the substation. The boundary between utility ownership and customer ownership matters because utility-owned infrastructure is typically included in rate base and potentially shared across all customers.

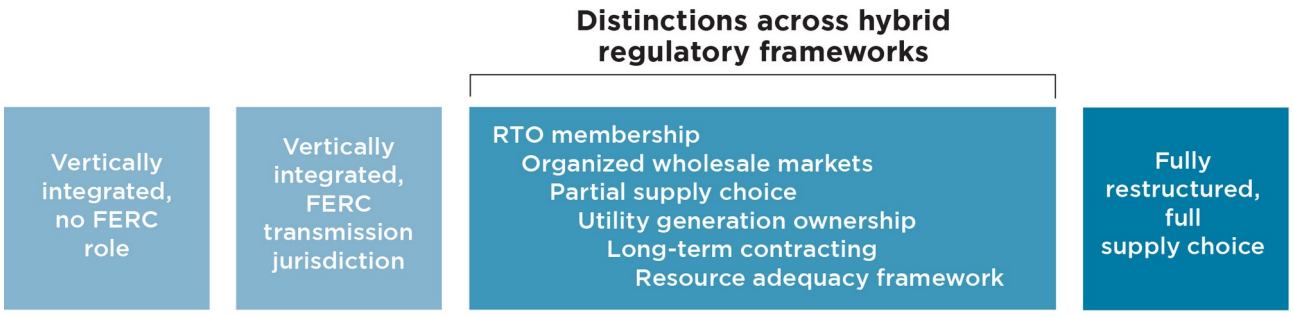
B. Regulatory Frameworks and Key Cases

There is no unified electricity regulatory framework across the United States. Depending on the level of detail considered, there are at least four different categories of regulatory frameworks for investor-owned utilities, with many more nuanced distinctions possible.

[21] These four types may not represent universal distinctions. Importantly, both type 2 and type 3 upgrades could potentially be shared among multiple customers over time. Type 1 infrastructure is never shared, and type 4 upgrades are always shared.

Figure 4 below illustrates the spectrum of electric regulatory frameworks across the country.

Figure 4. Spectrum of Electric Regulatory Frameworks in the United States



Across these regulatory frameworks, the term "load-serving entity" or LSE describes any organization that is responsible for supplying end-use customers. In vertically integrated jurisdictions, the entity that owns the distribution system serving the end-use customers is typically also the LSE for those customers. In fully restructured systems, there is more variation in who is an LSE because nonutility retail supply providers also fit within that definition. In many fully restructured states, the electric utilities that own the distribution system also serve as the administrators of basic or default supply service and are significant LSEs as a result.

Here and in Section IV, we will consider three different major regulatory frameworks: (1) a vertically integrated utility with FERC transmission jurisdiction and no RTO/ISO membership, (2) a vertically integrated utility with RTO/ISO membership and (3) fully restructured jurisdictions where generation has been divested and there is full retail supply choice.

Case 1: Vertically integrated utility with FERC transmission jurisdiction and no RTO/ISO membership

For our first major case, we will consider vertically integrated utilities in the continental United States where FERC exercises jurisdiction over transmission in interstate commerce, principally wholesale rates, as our first major case.[22] In this context, FERC sets wholesale transmission rates for these vertically integrated utilities, which effectively allocate transmission costs between the vertically integrated utility's retail customers and any other load-serving entities that use the utility's transmission system. That vertically integrated utility will also have a monopoly over the provision of generation services in most cases, although negotiation of a tariff arrangement or special contract for specific utility or

[22] In Hawaii and Alaska, there is no FERC role on these issues because there are no wholesale sales or transmission in interstate commerce under the Federal Power Act.

nonutility generation resources is sometimes possible. Major vertically integrated utilities that are not RTO/ISO members also frequently serve as a balancing authority for the purposes of dispatching generation and maintaining reliability standards. In their role as a balancing authority, these vertically integrated utilities also have authority over load curtailment when reliability is threatened.

Case 2: Vertically integrated utility with RTO/ISO membership

Next, while there are several differentiators across hybrid regulatory frameworks shown in Figure 4, we will consider a vertically integrated utility with RTO/ISO membership as our second major case. These utilities have turned over the operation of their transmission system to the RTO/ISO but may retain ownership. There are three distinctions for our purposes.

1. With respect to the interconnection of new data center customers, the exact arrangement depends on the RTO/ISO. In many cases, the transmission owner will manage the load interconnection process, but RTO/ISO will often have a role as well. The transmission owner and the retail electric utility may be the same entity, separate divisions of the same company or separate companies entirely.
2. In wholesale transmission cost allocation, the RTO/ISO and transmission owners, as overseen by FERC, have a different set of options because certain transmission costs are spread more broadly across the full RTO/ISO footprint.
3. The RTO/ISO serves as a balancing area authority and operates energy and ancillary service markets to optimize generation. The RTO/ISO also has authority over load curtailment for reliability purposes.

However, there may be ambiguity over the jurisdictional divide for certain responsibilities. Most relevantly, certain up-front fees and charges for interconnecting data center customers, such as CIAC,[23] could be handled as part of the load interconnection process with a transmission owner as overseen by the RTO/ISO and FERC. But alternatively, the contribution in aid of construction could be a retail rate policy handled by the retail utility as overseen by the state public utility commission.

Case 3: Fully restructured jurisdictions

Lastly, shown on the right of Figure 4, 13 states have elected to fully restructure their investor-owned electric utilities, requiring investor-owned utilities to sell their major generation facilities and offer retail supply choice for all IOU customers.[24] In these states, electric utilities have all joined an RTO/ISO, so this case is the same as case 2 with respect to the framework for transmission cost sharing across the full RTO/ISO footprint and

[23] A contribution in aid of construction is a requirement contained in line extension policies for new customers for many retail utilities. Typically, a new customer has a base allowance for the amount of investment the utility can make for the new customer, and any additional costs must be paid up front by the new customer. The base allowance is calculated from expected customer revenue and thus varies by customer class.

[24] Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Ohio, Illinois and Texas.

division of labor among RTOs, transmission owners and monopoly retail utilities in the interconnection process, with the RTO/ISO serving as the balancing authority.

The key distinction from case 2 for cost allocation purposes is the structure of the retail sector and options available for supply. For residential and small commercial customers, 12 of these 13 states provide for default or basic generation supply service, typically administered by the electric distribution company for its own retail customers. Most small customers remain on these default generation supply rates, although Texas does not provide a default option and requires customers to affirmatively choose a retail supplier. Many of these jurisdictions also offer a default supply rate for large industrial customers, although New York structures the default industrial generation supply service as a more complex mandatory hourly pricing product.[25] Retail customers in these states can contract with nonutility retail generation suppliers and pay a price agreed to with that supplier, instead of the default generation price. Structures like the New York mandatory hourly pricing program as well as "bring your own generation" requirements or incentives encourage large industrial customers to choose a nonutility retail generation supplier.

Wholesale Electricity Markets and Customer Risks

One element not explicitly identified in these three cases is the presence or absence of a wholesale electricity market. Organized wholesale energy markets are a foundational component of every RTO/ISO and have spread in the last decade in the non-RTO regions of the country, namely the Southeast and West. Even in the absence of organized wholesale markets, as a practical matter, bilateral transactions and other informal market mechanisms provide similar economic structures for investor-owned utilities across the country to buy and sell. With respect to electricity market prices, the key distinction across our three cases is that in cases 1 and 2, many vertically integrated utilities and their customers are protected in the short term from certain types of market price increases because these utilities use resource planning and procurement to secure long-term supply. In case 3, jurisdictions with retail supply choice have decided against long-term contracting for default supply service. This prevents the electric distribution utilities from exercising market power but can expose many customers to the risk of market price increases. While this risk is significant in an environment of load growth, it does protect these same customers from the potential costs of hedging strategies, such as any overly costly generation investments, stranded costs or above-market contracts. These issues are discussed further in the callout box below on page 11.

[25] Graves, C. (2009, October). *New York's mandatory hourly pricing program: Case 03-E-0641*. NYS Department of Public Service. https://www.nyiso.com/documents/20142/1404435/PRLWG_MHP_Overview.pdf/0d12b88b-2921-23c5-4c0f-2edb1d16257a

Hedging and the Impact of Wholesale Market Prices on Retail Customers

The impacts of wholesale market prices, through capacity markets, energy markets or non-ISO bilateral markets, on retail electricity customers depend on the degree to which their LSEs are exposed to these prices. If permitted, LSEs can use different strategies to plan for and build resource portfolios that determine their market price exposure and implicitly or explicitly hedge market risk.

In vertically integrated jurisdictions, utility LSEs often plan resources to meet their capacity and, in some cases, energy needs using integrated resource planning. Utilities then secure resources through either ownership or contracts, with the latter often taking the form of longer-term agreements. In states that offer retail supply choice, legislation, commission orders or regulations typically restrict the kinds of physical and financial contracts or instruments that utilities can include in default service procurement as a method to limit their market power. This means that their supply arrangements are often short term. Competitive retail suppliers in supply choice states have more flexibility in how they manage market risk because they are allowed to own generation resources and commit to long-term contracts. But as a practical matter, competitive suppliers often rely significantly on short-term supply arrangements to provide flexibility if customers move to another LSE.

All these arrangements — ownership, physical and financial contracting and other financial instruments — are forms of electricity market hedging. Utilities and retail suppliers can also hedge individual fuel prices, such as natural gas. Differences between LSE market risk management in restructured and vertically integrated states can be subtle, though the most important differences are likely in (1) how much of LSEs' loads are hedged on a forward basis (the degree to which their positions are long) and (2) the duration of those hedges. As a matter of law and policy, LSEs in restructured states have shorter, more open positions and shorter-term hedges. When market prices increase because of load growth, LSEs with longer positions (more generation resources than load commitments) will tend to have below-market costs and their customers can benefit. When market prices decrease, LSEs with longer positions will tend to have above-market costs.

Even though vertically integrated utilities and their retail customers may be hedged with respect to electricity market prices in some ways, they may be exposed to other risks more fully, such as fuel prices for their own generation facilities and the potential for stranded costs from investments and contracts that are no longer economically viable.

III. Cost Allocation Concepts in Ratemaking

As a specific ratemaking process step, cost allocation consists of (1) identifying distinct categories of costs, (2) identifying the groups of customers that those costs should be charged to and then (3) devising a fair and efficient way to divide those costs among the relevant groups of customers. This narrower definition of cost allocation applies to all the categories of costs recovered from electric customers through a traditional ratemaking process, spanning the cost of the electric system itself, administrative and general (A&G) costs for utility companies and public policy costs on electric bills. This is in significant part a zero-sum exercise for the utility and regulators, where a fixed revenue requirement is being divided up among ratepayers.

There are, however, three key ways in which cost allocation is not zero-sum. First, customer rate levels and design can influence load patterns and future system costs. Second, up-front payments from new customers lower the investment that utilities need to finance and thus reduce the future costs that need to be paid by all customers. Third, retail supply choice frameworks developed in the last 30 years operate under a different set of rules, without a fixed revenue requirement for the generation supply component of rates.

To guide the cost allocation process, experts frequently highlight two principles:

- **Principle 1:** “Costs follow benefits” or “beneficiary pays,” which considers who benefits from the investments.
- **Principle 2:** “Cost causation,” which considers the reasons why the costs were incurred.

RTO/ISO cost allocation processes overseen by FERC tend to focus on principle 1, beneficiary pays, because of judicial precedent under the Federal Power Act and related statutes. State utility commission proceedings more frequently cite principle 2, cost causation, but several states have invoked principle 1 recently in proactive planning proceedings.

In practice, these principles frequently align but may not always depending on how they are applied. As an example of when these principles align, utilities and regulators generally do not allocate distribution system costs to customers interconnected to the transmission system because transmission-connected customers do not benefit from or use the distribution system (principle 1) and they typically do not cause distribution system costs (principle 2). A frequent point of tension is when a single new customer triggers the need for a specific upgrade to the shared system. This new customer appears to be the “cost causer” under principle 2, but the grid upgrade may unlock benefits that also flow to a broader group of customers under principle 1. In recognition of this, the single new customer that caused the upgrades may only be charged for a portion of those specific shared upgrade costs.

Regardless of the principle invoked, regulators must make threshold decisions about how to account for and allocate costs mechanically. The Uniform System of Accounts (USOA) for electric utilities is a long-standing FERC regulation that all major utilities follow.[26] The USOA lays out major cost categories used for financial accounting; however, different cost accounts can be treated differently in ratemaking proceedings. Small cost items are typically grouped together and treated as a whole. For example, customer meter costs are not tracked individually, but rather collectively. Utilities develop ratemaking treatment for these assets on a group basis. It may be possible to track meter costs separately by customer class but frequently meters across all customer classes are tracked together in the Uniform System of Accounts. In a rate case, parties may contest the best way to allocate the meter accounts across customer classes.

For larger costs, such as a major transmission system upgrade, individualized treatment is administratively feasible. The specific investments costs can be directly assigned, but that means different things in different contexts. Sometimes the term "direct assignment" is used to refer to up-front payments for specific infrastructure investments. For example, a CIAC is an up-front payment by a customer, which typically flows from a specific set of investments to connect a new customer to the grid. The customer pays the CIAC before interconnection, so that portion of the costs is not part of the revenue requirement going forward. Direct assignment can also mean that a specific customer or group of customers is charged for costs over time through rates or contract payments. Mechanically, there are different ways to accomplish this, which are discussed below. Mixing and matching is also possible, where a percentage of the investment cost can be directly assigned and the remainder allocated in another manner.

Current cost allocation practices vary substantially depending on the regulatory framework. We first discuss retail cost allocation under traditional ratemaking, which can apply to generation, transmission and distribution costs, before turning to wholesale transmission cost allocation. This section concludes with a discussion of implicit and explicit cost allocation levers under retail supply choice frameworks.

A. Retail Cost Allocation under Traditional Ratemaking

Retail regulators[27] can use direct levers to adjust the allocation of costs across customer classes under the traditional ratemaking model. For example, when dividing a fixed revenue requirement, allocating more costs to data center customers generally means lower rates for other customers. This is true regardless of whether data centers are placed in an existing large industrial customer class or treated as a new customer class.[28] Utilities,

[26] Part 101 — Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

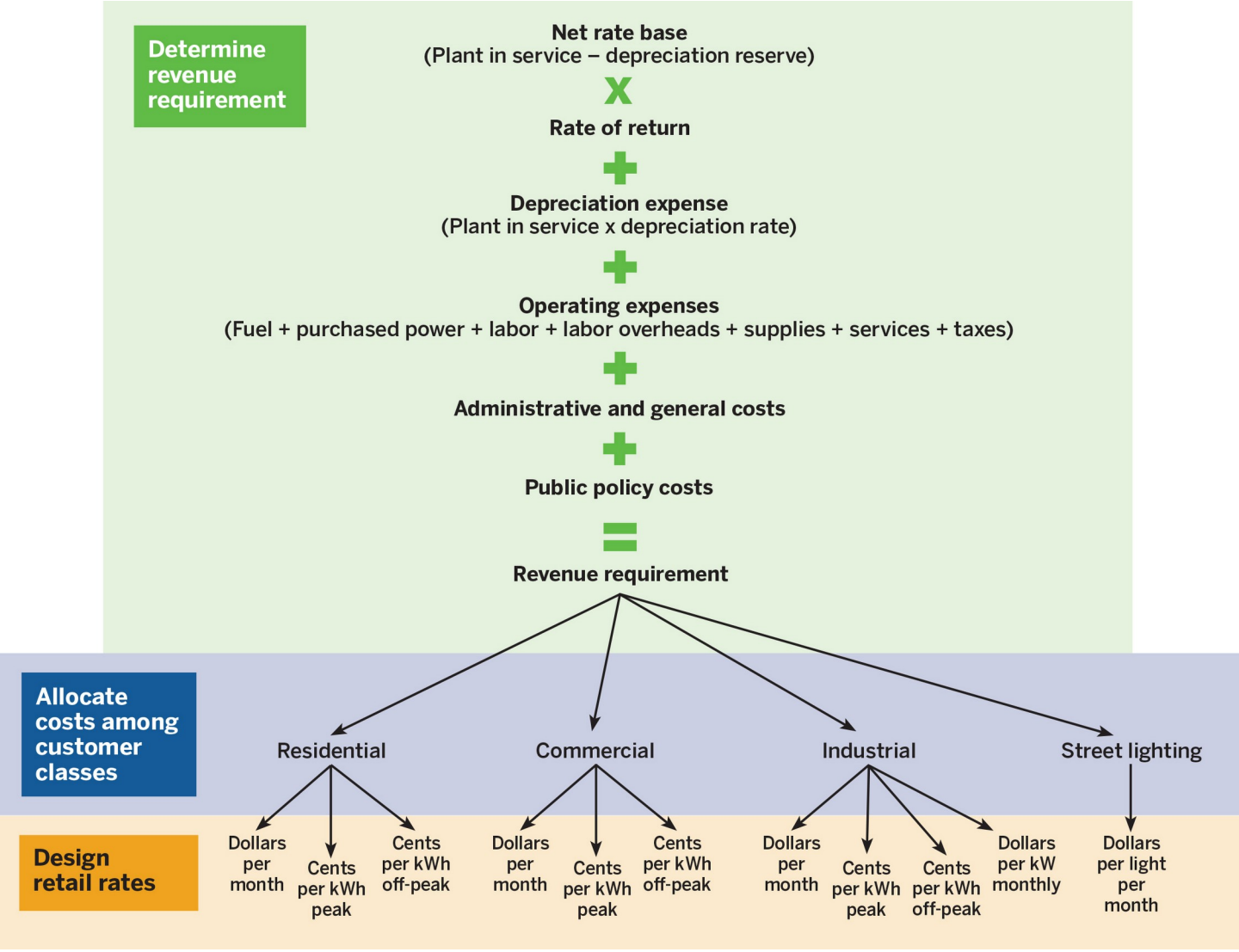
[27] We use "retail regulators" as a collective term for public utility commissions and the boards of co-ops and municipal utilities, as well as any other equivalent authorities.

[28] This distinction does matter to other industrial customers if the rates for a large load customer class are higher than preexisting industrial rates.

customer advocates and other stakeholders frequently debate the details of cost allocation in proceedings before the relevant regulatory body to establish utility rates; these proceedings are also known as rate cases. In these proceedings, retail regulators can revisit key cost allocation methods and assumptions, which in turn influence the proportion of costs charged to data centers and other customers. In a few cases, regulation or statute dictates cost allocation methods and assumptions, but more commonly, commission orders address or revise cost allocation issues.

Figure 5 presents a simplified version of these steps for a vertically integrated investor-owned electric utility in a rate case at a state utility commission.

Figure 5. Simplified Vertically Integrated Electric Utility Ratemaking Steps



Shown in green in Figure 5, a utility's revenue requirement includes all costs that need to be recovered over time, calculated as a one-year snapshot. This is typically the revenue level that the utility expects to collect in the rate year following the conclusion of the rate case. For vertically integrated utilities, the revenue requirement covers generation, transmission and distribution. The revenue requirement calculation is appropriately narrowed for other types of utilities and cost recovery processes. For example, in fully restructured jurisdictions, distribution-only investor-owned utilities have rate cases that cover only their distribution revenues and rates.

The annualized revenue requirement is then used during the next step of the process, cost allocation, shown in blue. This is the narrowest and most technical definition of cost allocation, as it pertains to a specific step of a rate case. Although there are exceptions, retail cost allocation and rates typically do not make any geographic distinctions within utility service territories, a concept known as postage stamp pricing. Postage stamp pricing promotes simplicity and equity across customers within a utility service territory but potentially comes at the expense of less economically efficient cost allocation and pricing.

At the retail level, the cost allocation step divides the revenue requirement among categories of utility customers, known as customer classes. These customer classes are usually broad and intended to capture cost differentials between different types of customers. Some utilities have many customer classes, but typical classes for each utility include residential customers, small business customers, large commercial and industrial (C&I) customers and street lighting customers. Some jurisdictions have implemented new customer classes for large load customers as a response to concerns about rate impacts on other customers. Otherwise, large data centers fall into the class with the largest industrial customers. This step in the process ends with a specific level of revenue that should be collected from each broad customer class.

For the most part, cost allocation is based on quantitative analysis to divide major groups of costs across customer classes. The Uniform System of Accounts provides a convenient way to group costs, and different quantitative formulas can be applied to each account; however, direct assignment replaces this analytical step. Regulators and utilities can identify specific costs and directly add them to the revenue responsibility for a given customer class. Further details on analytical methods in retail cost allocation are in the callout box below on page 16.

The final step in the ratemaking process is rate design, shown in orange. With respect to cost allocation, rate design determines *intraclass cost allocation*. While each customer *within* a class pays the same rates, they have their own usage patterns and billing determinants, resulting in different bills. This means customers pay different proportions of the revenue assigned to the overall class. Changes to rate design leads to changes in the relative contributions from individual customers within a class.

Analytical Methods in Retail Cost Allocation

Specific analytical techniques for cost allocation have long been debated in state utility commission proceedings, and related analytical debates take place at FERC and in RTO/ISOs. State proceedings have developed a major distinction between "embedded cost of service" techniques, which are more common, and "marginal cost of service" techniques, which arose in the 1970s. Embedded cost studies use analytical techniques to directly divide up the existing costs that are built into rates. In contrast, marginal cost techniques are explicitly forward looking but require adjustments to ensure that the correct revenue levels are collected. Marginal cost-of-service methods spread across the country in the 1980s but are now primarily used in California and Nevada for ratemaking purposes. The New York Department of Public Service has investigated marginal cost-of-service studies in recent years as well.

Although both embedded and marginal cost studies include precise calculations, most regulators are not strictly bound by the results. Numerous other factors are involved in cost allocation for each rate case, including gradualism of rate changes, policy considerations and economic conditions in the service territory. The data developed for cost allocation and the analytical techniques used in the cost-of-service studies can provide helpful information for other purposes, such as rate design. Analysts must pay careful attention, however, to the reason the data were developed, and caution must be taken so that this information is used constructively in an appropriate manner.

Older analytical techniques for cost allocation were developed during a time when data storage and quantitative analysis were much more difficult than today and system information was much more limited. Modern spreadsheet software did not exist in the 1950s or 1960s, and the utilities had minimal monitoring capabilities for customers and most parts of the electric system. These older techniques were, quite reasonably, simplifications based on the available data and structure of the electric system at the time. How to modernize cost allocation given the capabilities and realities of today is discussed at length in *Electric Cost Allocation for a New Era*.[29] Analysts can update embedded cost methods, but adoption of marginal cost techniques may help solve other modern regulatory challenges.

[29] Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (2020, January). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

Retail cost allocation is not limited to rate case proceedings. Utility commissions consider special contracts between utilities and large customers in individualized proceedings.[30] Adjustment clauses, also known as riders or trackers, are another ratemaking mechanism that utilities and commissions use to charge costs outside of base rates determined in a rate case. These can apply broadly or narrowly and can recover costs from different groups of customers. In theory, a rider can apply to all customers, all customers within a customer class, subsets of customers across more than one class or even just one single customer. As a result, regulators can use riders as a method to directly assign costs if the regulator and utility can clearly identify which customers need to be assigned the relevant costs. Most vertically integrated utilities have a fuel and purchased power adjustment clause that allows for updates between rate cases. This applies broadly to all customers, and the division of costs across customer classes is typically set in advance.

B. Wholesale Transmission Cost Allocation

In the modern regulatory system, FERC oversees transmission costs for much of the country. FERC, RTO/ISOs and transmission owners can shape the structure of wholesale transmission rates, and subsequent state decisions cannot challenge the validity of these wholesale rates.[31] There are ambiguities in the jurisdictional lines as well. For example, RTO/ISOs and state-jurisdictional retail utilities may have overlapping or shared responsibility for the connection of new data center customers to the transmission system. Clarity and information sharing are necessary to coordinate cost sharing across federal-state jurisdictional boundaries and over time. To take a simple example, states and RTO/ISOs should not charge separate contributions in aid of construction to interconnecting data center customers that cover the same costs. Similar questions may arise about exit fees.

For investor-owned utilities that are not a member of an RTO/ISO, wholesale transmission cost allocation determines how costs are divided between the utility's own retail customers and other load-serving entities that use that utility's transmission system. As discussed above, the state utility commission has jurisdiction over how wholesale transmission costs are allocated and priced to retail customers for investor-owned utilities. In many cases, the other load-serving entities using the investor-owned utility's transmission system will be a co-op or government-owned utility, whose board has authority over retail cost allocation.

[30] Special contracts, as the name implies, are unique arrangements between state-jurisdictional utilities and large customers. These occur outside the normal rate case process and typically must be approved individually by the state utility commission. Special contracts do not necessarily have an immediate and direct impact on rates for other existing customers, but these can be synchronized over time. For example, special contracts typically ensure that customers cover at least their marginal costs and phase out after a predetermined period, for example, five, 10, or 15 years, after which the customer is subject to the otherwise applicable utility rate.

[31] *Nantahala Power & Light v. Thornburg,* 476 U.S. 953 (1986).

In May 2025, Lawrence Berkeley National Lab published a report that addresses wholesale transmission cost allocation for RTO/ISOs in detail.[32] While the charges to interconnecting generators can be significant,[33] the bulk of transmission costs for each RTO/ISO are charged to wholesale load customers within the RTO/ISO footprint. Unlike the retail context, there are no "customer classes" with different rates. However, each ISO/RTO tends to categorize transmission infrastructure to allow choices about how broadly each category of costs is spread across the footprint geographically, although each RTO/ISOs have chosen different categorizations. For a given category of costs, they can be shared across the entire RTO/ISO footprint or attributed locally to a specific load-serving entity, but some RTO/ISOs have also set up zones or subregions that are smaller than the entire footprint and larger than a single entity. These geographic distinctions lead to variance in rates across wholesale load customers within each RTO/ISO footprint. Higher wholesale transmission rates will tend to lead to higher retail rates as wholesale costs get passed on to retail customers.

C. Retail Supply Choice Frameworks

The structure and oversight of retail generation supply rates in fully restructured jurisdictions is conceptually different than the traditional ratemaking structures described above. Regulators are no longer dividing a fixed revenue requirement over a captive customer base. Retail supply prices are determined by the combination of RTO/ISO wholesale energy market structures overseen by FERC and state retail supply rules. In jurisdictions other than Texas, most residential and small commercial customers are on a default or basic service supply rate,[34] but other competitive retail suppliers are allowed to market retail supply service to these customers. Industrial customers tend to participate in retail supply choice at higher levels than small customers and are generally more sophisticated in their ability to bargain with competitive retail suppliers.

Across these contexts, the basic structure of retail supply choice is that certain parts of electricity rates are labeled as non-bypassable. These are the portions of the electricity rate that a customer must pay regardless of whether the customer chooses a competitive retail supplier or stays on a default energy supply rate. Conversely, the costs built into default energy supply rate can be called bypassable because the customer no longer pays those

[32] Kahrl, F., Schellenberg, J., Schwartz, L., Rojas, D. R., Tarufelli, B., Wilson, K., & Homer, J. (2025, May). *Transmission cost allocation practices.* Energy Markets & Planning, Berkeley Lab. https://eta-publications.lbl.gov/sites/default/files/2026-01/transmission_cost_allocation_brief_final_v2.pdf. There were two significant reports on wholesale transmission cost allocation in 2026: Kershaw, G., Wilson, J. D., Gramlich, R., & Meyer, S. (2026, May). *Federal transmission pricing*, vol. 1; and Meyer, S., Kershaw, G., Wilson, J. D., & Gramlich, R. (2026, June). *Federal transmission pricing*, vol. 2. Grid Strategies. https://gridstrategiesllc.com/project/federal-transmission-pricing/. See also Rose, A., Simeone, C., Estreich, E., & Foss, N. (2026, February*). Lessons learned for transmission cost allocation in U.S. regional markets.* National Laboratory of the Rockies. https://docs.nlr.gov/docs/fy26osti/97370.pdf

[33] Each RTO/ISO has developed methods for charging new generation facilities to interconnect to the transmission system. In each of the six FERC-regulated RTO/ISOs, each generator must pay for the entirety of "attachment facility" costs, which is the generator equivalent of a service line. In addition, new generators must pay for broader transmission network upgrades in many cases, but the exact proportions and formulas vary by RTO/ISO and by situation. Kahrl et al., 2025, pp. 9-11.

[34] Notably, the majority of residential customers in Massachusetts are now served by municipal aggregators who procure supply services from retail providers. Municipal aggregators typically provide the customers they serve with multiple supply options, including a default service option.

charges after choosing a competitive supplier.[35] Instead, the customer pays the energy supply rate agreed to with the competitive supplier. State utility commissions have some discretion over which costs are non-bypassable. However, the details of commission discretion under existing statutes and regulations vary from jurisdiction to jurisdiction. Similar questions arise in hybrid jurisdictions that offer partial retail supply choice.

This retail supply choice framework for generation does not lead to the same zero-sum structure as cost allocation under traditional ratemaking. By itself, a higher retail generation supply rate for data centers in these jurisdictions does not translate directly to lower retail supply rates for other customers. If load growth leads to higher electricity market prices, increases in supply costs are not allocated by state utility commissions but instead are reflected in the prices offered by retail suppliers. Prices from competitive supply providers are based on the wholesale energy markets, the provider's procurement strategy, and any negotiation between the provider and the customer. The default supply rate comes from the procurements and competitive solicitations conducted by the utility. Utility procurement methods are guided by state commission rules and orders under the relevant statutes, but utilities often have significant discretion. Different jurisdictions make different choices about the level of hedging built into default supply rates. Hedging provides more stability for the default supply rate but can be costly. A fixed long-term contract can appear expensive in retrospect if market prices decline over time.

IV. The Full Picture of Costs and Revenues from Data Center Load Growth

We can now put together the pieces of the cost allocation puzzle. First, load growth due to data centers incurs specific types of costs, direct utility expenses and infrastructure but also changes outcomes in wholesale electricity markets. These costs are incorporated into retail rates through different mechanisms depending on the regulatory framework. How these costs are incorporated into retail rates is the most straightforward for regulated assets that are subject to traditional economic regulation and ratemaking. But the economics of load growth in wholesale electricity markets is often more complex and the ultimate impact on retail rate customers depends on how load-serving entities are hedged and otherwise positioned in wholesale electricity markets. There is a risk of stranded costs for regulated assets as well.

Separately, we can examine in detail the different categories of financial contributions from data centers across the full customer life cycle. These can be categorized and described generically but are implemented differently across regulatory frameworks. Lastly, we can bring together consideration of financial contributions of data centers and the costs caused

[35] Jurisdictions have different approaches to transmission costs under this framework. In ISO-NE, transmission costs are fully non-bypassable and treated as a retail ratemaking issue outside retail supply choice. In portions of PJM, transmission costs are part of retail supply choice. The competitive retail supplier is charged a wholesale transmission rate as a load-serving entity and includes those costs in the price offered to its customers.

by data centers that are included in customer rates. Under each of our three key regulatory frameworks, we look at the decision points that ultimately determine the share of costs covered by data center customers and by other electric customers.

A. Costs Caused by Data Center Customers

We will examine costs caused by data centers across three categories: (1) interconnection studies and initial administrative process costs, (2) interconnection facilities and local network upgrades and (3) broader generation and transmission costs.[36] For broader generation and transmission costs, we will distinguish between our three key cases laid out in Section II: (1) a vertically integrated utility with FERC transmission jurisdiction and no RTO/ISO membership, (2) a vertically integrated utility with RTO/ISO membership and (3) fully restructured jurisdictions where generation has been divested and there is full retail supply choice.

Load Interconnection Study and Administrative Process Costs

Modern data centers have high enough electricity demand that they typically connect to the transmission system and require an up-front study by a transmission owner or RTO/ISO.[37] How much this study costs and what is required of the study depends on the size of the proposed load, point of connection and other factors. These initial studies and administrative process costs are the starting point for all significant new data center customers.[38] With a sufficient volume of data center customer interconnection requests in a given region, some regulatory authorities have switched to group or cluster interconnection studies, which can lead to cost sharing from connecting customers.

Interconnection Facilities and Local Network Upgrade Costs

New load interconnection studies identify specific delivery network costs. Those costs are necessary to connect the customer to the system and ensure the safety and reliability of the network after the customer commences operation. These costs are illustrated in Figure 3 in Section II above but are worth revisiting in some detail here.

First, there is a service line, or potentially multiple service lines, connecting the data center to the shared portion of the electric delivery system, whether the point of connection is on the distribution system or transmission system. This infrastructure is specific to the

[36] For distribution-connected data centers, there may also be more general distribution system upgrades and expansion costs due to load growth that are not specifically attributed to a data center in the interconnection process. Such incremental distribution system costs will always be state jurisdictional for investor-owned utilities and should be allocated equitably through the relevant state ratemaking processes.

[37] Energy Systems Integration Group. (2026, June). *Interconnection processes for large loads: Current practices and recommendations.* https://www.esig.energy/reports-briefs/large-load-interconnection-process/

[38] Small data centers may have loads similar to major retail stores or other commercial customers and can follow more routine procedures designed for those more familiar customers. These loads may still require interconnection studies, but the issues are likely more routine and the risks proportionately fewer.

individual data center customer, benefits no other customers and is larger in size and complexity than a service line for a residential or small commercial customer. The size and cost of this infrastructure may be similar to other very large electricity consumers but may also have analogs with the size and cost of the interconnection lines for major electric generation facilities.

Second, upgrades to and reconfiguration of the local network or even a broader area are often necessary for the connection of large customers. If a data center connects to the primary voltage distribution system, this would impact the relevant circuit wiring and protections and substation upgrades, and the necessary upgrades could include transmission system infrastructure past the distribution substation. If a data center connects to the transmission system, it could trigger a variety of shared transmission system upgrades. These transmission system upgrades may necessarily implicate a larger portion of the regional network if the new data center load is sufficiently large. Data center connections to the transmission system may also implicate the distribution system under certain circumstances. Other customers may benefit in the short and long term from these new, shared delivery system investments.

Broader Generation and Transmission Costs

Separately, there are costs of load growth outside those identified in a single new load interconnection study or even a cluster study. These costs can span higher wholesale electricity market costs, higher generation dispatch costs and a mix of investments in large-scale generation resources and regional transmission, as well as more local supply alternatives to those investments. The scale depends on the resource adequacy headroom for the relevant utility, control area or RTO/ISO zone or region. If a data center happens to locate in an area with excess capacity and it is sized to fit within that headroom, these costs could be modest and limited to increased fuel and purchased power costs in vertically integrated states and increased market prices in restructured states. Given the scale of current data center applications, both individually and collectively, having sufficient headroom appears to be unlikely in several parts of the country. These broader transmission and generation costs can be difficult to attribute to individual customers, and the exact structure of costs varies depending on the regulatory framework. We start by discussing common threads across regulatory frameworks before examining distinctions across the three key regulatory frameworks described in Section II.B.

In the short run, if the data center connects and begins operation prior to supportive investments, there will be higher usage of existing generation resources and transmission infrastructure. The general impact will be higher market prices and more frequent dispatch of higher marginal cost resources. In addition, higher use of the transmission system requires additional generation to make up for the increases in line losses. Organized wholesale markets structure these dispatch and transactional decisions rationally across all

participants if well designed. The optimal answer will depend on whether other generation owners and load-serving entities participating in wholesale transactions are experiencing similar load growth and the relative cost of generation facilities.

In the longer term, utilities and many other LSEs have a "build or buy" decision, and large customers can also support supply alternatives specifically, whether that is (1) utility-owned generation resources, (2) independent power producer generation connected to the bulk transmission system, (3) resources behind the meter at the data center site or (4) distributed energy resources (DERs) and energy efficiency at other customer locations. Large-scale generation, whether owned by a utility or independent power producer, is more likely to need supportive regional transmission build-out. Self-generation at the data center customer site may lower regional transmission needs, but there are risks and questions about the frequency and amount of electricity needed from the grid and the extent to which supportive bulk system investments would still be necessary and economic. Energy efficiency and DERs at other customer locations will not remove the need for local transmission upgrades to serve a new data center even if these demand-side resources contribute to regional energy and resource adequacy.[39]

Bringing online new generation resources and corresponding transmission infrastructure attenuates the short-term energy supply and market price impacts of data center load growth. Theoretically, if a data center brings generation resources perfectly matched to its new load, any energy supply impacts disappear. In practice, the details vary depending on the load characteristics of the new data center demand, the characteristics of the incremental supply resources, whether new data center demand impacts commodity prices and other factors such as congestion and line losses on the transmission system. Another key question is the timeline for any build options, from large-scale generation facilities to energy efficiency and DERs. Small-scale alternatives may be more likely to be completed quickly, even possibly before the data center begins operation, but the quantities may be uncertain.

Additional information on the cost allocation and jurisdictional implications across our three cases is detailed below.

Case 1: Vertically Integrated Utility Without RTO Membership

In this case, the vertically integrated utility is the primary entity to manage and plan for the load growth from new data center customers with oversight from the state utility commission. If the utility is connected to a formal or informal wholesale market, it has an option to dispatch its own units more often. The details depend on whether it was a net buyer or seller previously. If the LSE is a net buyer, the choice is whether to buy more or dispatch more. If a net seller, the choice is whether to sell less or dispatch more.

[39] These energy efficiency measures and DERs may reduce regional upgrades and even some more local transmission upgrades that would otherwise have been needed.

Once new infrastructure investments have been completed, as well as any options that show up as an expense in the utility revenue requirement, then those costs flow into rates via rate adjustment mechanisms or a subsequent rate case. If the utility tracks incremental load from a new data center customer, then vertically integrated utilities typically have detailed generation cost and purchased power data to directly calculate the incremental costs caused by the new customer. With respect to transmission, FERC-jurisdictional wholesale rates are either updated through a formula rates process or wholesale transmission rate cases at FERC.

Case 2: Vertically Integrated Utility with RTO Membership

The primary difference between case 1 and case 2 is that the RTO/ISO has responsibility over transmission planning and cost recovery in conjunction with the transmission owners. Transmission planning ends up being mostly separated from generation supply decisions because authority is split across jurisdictional lines, but there may be shared authority and necessary cooperation in the interconnection process across jurisdictional lines. Incremental generation costs are handled through state commission processes, but changes to wholesale transmission rates go through FERC-approved rates from the RTO/ISO and transmission owner before going into the retail revenue requirement.

Case 3: Fully Restructured Jurisdiction with Retail Supply Choice

With respect to transmission, case 3 is similar to case 2. For generation costs, supply decisions have moved further from the direct control of the state utility commission and the state-jurisdictional retail investor-owned utility in favor of decisions by customers and producers guided by the markets. Wholesale market price changes are intended to drive changes in investment behavior for all market participants. Independent power producers, either on their own or in collaboration with specific customers, should be encouraged to invest in more generation resources by higher market prices. Public policy initiatives by the states or federal government can also encourage or hinder new investment.

B. Ratepayer Risks from Market Price Impacts and Stranded Costs

While the analysis of costs caused by data center load growth is complex on its own, additional regulatory layers determine a data center customer's impact on other customers' rates. First is the extent to which customers are exposed to market price impacts. Second is the potential risk of stranded costs.

Ratepayer Exposure to Market Price Impacts

As described in Section II above and Appendix A in more detail, most major utilities in the mainland United States now participate in a wholesale energy market to some degree. The details of that participation vary greatly and differ in kind between the two poles of our spectrum: (1) vertically integrated utilities that participate in markets and (2) fully restructured jurisdictions where wholesale markets are central to the regulatory framework.

Under current practices, ratepayers are much more exposed to wholesale electricity market price impacts in fully restructured jurisdictions.[40] This is partially by design, because theoretically it allows ratepayers to make their own decisions about consumption and what competitive retail supply option they choose. But in practice, small customers in restructured jurisdictions generally stay on default supply service, and their exposure to market price impacts depends largely on the default generation supply procurement.

Default generation supply procurement structure is typically set in legislation or utility commission regulations and orders, and the actual procurements are administered with some discretion by local electric distribution companies. The relevant statutes, regulations and orders may allow for different levels of hedging through forward-looking contracting for the different components of default supply service. In some PJM jurisdictions, such as Maryland, the distribution utilities procure two-year contracts to provide some stability over time.[41] Other jurisdictions, however, such as Massachusetts only use one-year procurements, which likely leads to more volatility.[42] Individual states have different statutory features and limitations. One example that differs from the typical model is Illinois. The Illinois Power Authority is a state agency charged with overseeing small customer default supply procurement strategies across ComEd (in PJM) and Ameren and MidAmerican (in MISO or Midcontinent Independent System Operator) and submitting those strategies and procurements to the Illinois Commerce Commission for approval.[43]

The one exception to this default supply service structure is the investor-owned utility service territories in ERCOT (Electric Reliability Council of Texas) in Texas. Because there is no generally available default supply service, customers can be exposed to market price impacts, but this depends on the supplier they have chosen. Some Texas supply retailers have had pricing strategies and contracts with customers that directly and purposefully fully

[40] This discussion excludes indirect cost impacts, such as upward pressure on equipment prices, and underlying commodities, such as natural gas.

[41] Office of People's Counsel, State of Maryland. (n.d.). *Utility (standard offer service) rates.* https://opc.maryland.gov/Consumer-Learning/Electricity/Utility-Standard-Offer-Service-Rates

[42] Commonwealth of Massachusetts. (n.d.). *Basic service information and rates*. Mass.gov. https://www.mass.gov/info-details/basic-service-information-and-rates

[43] Illinois Power Agency. (n.d.). *Electricity Procurement Plan*. https://ipa.illinois.gov/electricity-procurement/electricity-procurement-plan.html

exposed customers to wholesale energy market prices.[44] However, such supply pricing practices are not widespread, even in Texas.

In every fully restructured jurisdiction, competitive retail supply providers may choose the level and types of hedging that they offer to customers and build those features directly into customer prices. While state statute typically prohibits local electric distribution companies from directly owning generation assets that would serve as a hedging mechanism, other retail suppliers are allowed to own generation assets and have fewer restrictions on their contracting choices than default supply procurements overseen by the state commissions.

Ratepayers in vertically integrated and hybrid regulatory frameworks often have built-in hedges that shield them from market price impacts. Ownership of generation assets by retail investor-owned utilities serves as a hedge from market price impacts due to load growth. For example, Dominion in Virginia participates in PJM but owns major electric generation units. Dominion executives have publicly asserted that generation ownership has protected their ratepayers from the recent increases in PJM capacity market prices.[45]

All hedging features have costs and are not a perfect solution in all circumstances. LSEs and policymakers must evaluate the costs and risks of different hedging options along with their benefits. Long-term contracts can end up acting as a hedging mechanism for wholesale market prices across regulatory frameworks unless they are pegged to the market price. Long-term contracts may or may not be a good deal for ratepayers over the term of the contract. Utility asset ownership has its own set of ratepayer risks, starting with the costs of building and maintaining the asset and extending to the potential for stranded costs as discussed in the next section. Above-market contracts can also be considered a form of stranded cost.

Potential for Stranded Assets and Costs

A stranded asset is one that is no longer economically useful, but the utility has not recovered its capital investment yet. While it would make economic sense to shut down such a facility, that means the utility would forgo the recovery of the remaining book value, absent special regulatory treatment. The prototypical stranded asset risk is a major utility-owned generation facility, such as a nuclear plant, that turns out to be more expensive than projected and simultaneously turns out to not be needed to meet demand because actual load ended up lower than the forecasts. This situation happened to several different utilities in the 1980s and led to difficult state commission decisions, major litigation with multiple U.S. Supreme Court decisions and at least one utility bankruptcy. One major benefit of full restructuring is that retail customers are no longer potentially on the hook for the stranded

[44] Skyrocketing wholesale prices during Winter Storm Uri in 2021 led to the bankruptcy of one retail supplier that used this pricing practice. See Brooks, K. J. (2021, March 15). *Texas electricity company Griddy declares bankruptcy as winter storm fallout continues.* CBS News. https://www.cbsnews.com/news/griddy-energy-texas-files-bankruptcy/

[45] DiGangi, D. (2024, August 7). *Dominion says ratepayers will be insulated from PJM capacity auction impacts.* Utility Dive. https://www.utilitydive.com/news/dominion-rate-payers-capacity-auction-pjm-generation/723535/

costs of major generation investments by traditionally regulated utilities. Instead, generation owners in the market bear more risk regarding the operation of their facilities but may also have more upside from favorable market circumstances over the lifetime of the asset.

Stranded assets, and related decisions about where to place the remaining costs of those assets, are only a risk for customers of traditionally regulated entities when the relevant asset is owned by that entity. We can look at stranded asset potential across two of the same categories above: (1) interconnection facilities and local network upgrades and (2) broader generation and transmission investments.[46] The service connection infrastructure could become a stranded asset if the customer shuts down and the asset is not reused by a new customer or customers in the same location.[47] It would rarely make sense to "undo" other local network upgrades that occurred because they do benefit the shared system and other customers. Furthermore, if the service connection infrastructure and local network upgrades have been fully covered by a CIAC, there is no risk of stranded costs.

Broader generation and transmission costs may end up stranded if there is significant overcapacity. That's an inherent risk of forecasting major demand increases. Without sufficient safeguards in place, forecasts may reflect duplicative requests from a small number of projects to maximize the chance of securing fast connections,[48] and speculative developers submit requests that bet on future data center demand.[49] The lack of historical data — about realization rates, project completion timelines or facility lifespans — makes it even more challenging for utilities and regulators to sort the wheat from the chaff. To the extent that this problem is specific to new investments in generation assets by vertically integrated utilities, tools exist to separate the cost of new assets to ensure that the new customers bear the risk of stranded assets. Ring-fencing or the creation of a new separate corporation to own the new utility assets to serve a data center is essentially a form of restructuring and alternative supply.

Stranded costs due to the shut down of a major data center customer prior to the end of its expected lifespan could potentially be offset by exit fee requirements in tariffs or the special contract for that data center customer. Of course, the customer in question must have sufficient assets to pay the exit fee, making collateral requirements and other financial guarantees vitally important. Bankruptcy proceedings for the customer could put the collection of the exit fee at risk or delay it substantially. In certain cases, the customer may

[46] The third category discussed above, interconnection study and administrative process costs, should be fully paid for by the requesting customer.

[47] In principle, major service line infrastructure can be reused by the same utility in another location or sold to other utilities. If the equipment can be reused, it is not a fully stranded asset if the costs of disassembly and repurposing are lower than a new installation in the other location. If the equipment is sold, then the stranded cost is the remaining book value minus the net salvage value, which is the sale revenue minus the cost of removal.

[48] An energy market development lead for Google noted that during the planning stage, "the same entity might make multiple requests for the same unit of supply, but only a portion of planned data centers ultimately get built." Sawyer, A. (2025, May 20). *Uncertainty in data center load forecasts creates planning difficulties*. NewsData. https://www.newsdata.com/clearing_up/supply_and_demand/uncertainty-in-data-center-load-forecasts-creates-planning-difficulties/article_66bb1c5a-0a1e-453d-a2b4-985f2ee0f651.html

[49] Wilson, J. D., & Meyer, S. (2025, December). *Forecasting for large loads: Current practices and recommendations.* Energy Systems Integration Group. https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Large-Loads-Forecasting-report-2025.pdf

be a subsidiary of a larger corporation, and the larger corporation may have protections from liability for the debts and obligations of its subsidiaries.

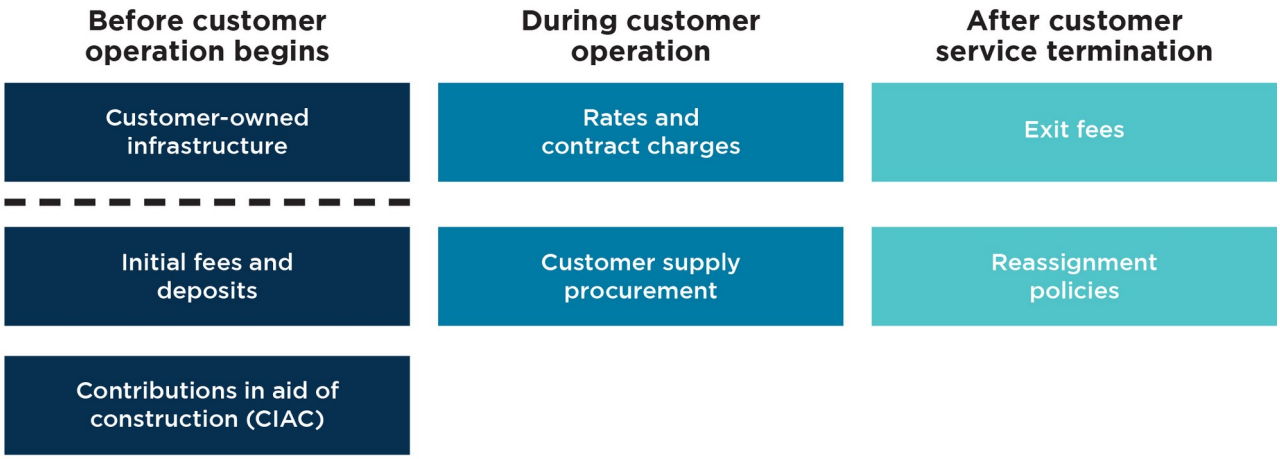
Significant overcapacity may not show up as a traditional stranded asset problem for the specific new generation and transmission investments made concurrently with data center load growth. Those assets may still be used and useful if they are completed and serve the system. Overcapacity more generally would lead older, higher-cost generation units to shut down instead. Such asset retirements may still represent stranded costs if their capital depreciation period has not been completed.

C. Life Cycle of Financial Contributions from Data Centers

Comprehensive evaluation of cost allocation, as well as net costs and risks to other ratepayers, should consider the full life cycle of revenue from data center customers. So long as the total revenues recovered over the life cycle are larger than the cost to serve (in net present value), other customers should be insulated, and their rates would be lower than the counterfactual without the data center load growth. Until sufficient revenue is recovered, however, the utility's other ratepayers and shareholders are at risk. The earlier relevant costs are recovered, the lower the risk to nonparticipating ratepayers over time. Underrecovery is possible for many different reasons, such as a slower ramp-up period or early data center closure. In addition, data center customer bankruptcy may cut off future obligations, leaving everyone else on the hook. Early cost recovery should be balanced with other considerations, such as efficient pricing to help shape data center load patterns. Understanding the full scope of the different potential contribution points over time is necessary before mapping different costs to different data center financial contributions.[50] This can be divided into three categories as shown in Figure 6 below: (1) before customer operation begins, (2) during customer operation and (3) after customer service termination.

[50] Further detail on rate designs and other related practices for data centers at Frick, N. M., Cappers, P., Kavlak, G., Lam, L., Hledik, R., Grove, J., & Rotella, S. (2026, August). *Electricity rate designs for large loads: Evolving practices and opportunities 2026 update,* Energy Markets & Planning, Berkeley Lab. https://emp.lbl.gov/publications/electricity-rate-designs-large-0

Figure 6. Full Life Cycle of Financial Contributions from Data Centers



Before Customer Operation Begins

The financial relationship between data center customers and a retail utility or RTO begins when the customer first initiates an inquiry about a potential interconnection. This starts with any fees required during the interconnection process. Covering administrative processes and interconnection studies with fees prevents the costs from going into a relevant revenue requirement. To the extent that data center customers cover these costs directly and up front, there is no risk to other customers.

Another option is customer ownership of infrastructure, including substations, transformers, poles, wires and purchases of land or easements for that infrastructure. While this is less common for small customers, this is a more widespread practice for certain types of large customers. Note that the utility graphic in Figure 3 specifically includes a customer-owned substation for a transmission-connected data center. If a customer owns the infrastructure, the customer must maintain the infrastructure at its own expense, including any property taxes. This excludes the relevant assets from the utility rate base and means that O&M costs for customer-owned assets are not a risk to other retail customers. Under some existing tariffs, customers are given a discounted rate if they own relevant infrastructure on the customer side of the meter and avoid the need for the corresponding utility-owned infrastructure.

Retail utilities typically have existing contribution in aid of construction (CIAC) policies built into their tariffs. In contrast to customer ownership of infrastructure, that means the customer pays to cover some or all of the relevant capital investment, but the utility owns the asset. The utility, in turn, covers the maintenance costs and pays any relevant property taxes. CIAC policies can be designed in many ways, but their purpose is to protect other existing customers from the unreasonable cost of connecting a new customer.

One stereotypical application is a new residential customer far from existing utility infrastructure, but still within the utility service territory. Utility line extension policies typically have a baseline allowance for interconnection costs that the utility can spend to connect the new customer, and then the new customer must cover any costs over and above the baseline allowance level. The baseline allowance level will differ by customer and customer class because the expected revenue from that customer over time is different. How much of the expected revenue is incorporated into the baseline allowance can also differ by utility and customer class. One long-term issue with this approach is that utilities are obligated to replace these assets when they fail or reach the end of their life. The cost of replacement is then typically socialized across all customers, with no new contribution in aid of construction from the specific customer.

Customer contributions to construction can sometimes be fully or partially refundable if other interconnecting customers end up using and benefitting from the relevant infrastructure. This refundable structure is sometimes called a customer advance. Data center customers have proposed additional voluntary contributions in aid of construction in exchange for prioritization in load interconnection processes, but it is important to understand that typical CIAC policies are a requirement, not an option.

The purpose of other customer deposits is harder to describe generically, but up-front customer deposits shield other ratepayers from risk as well, and deposit return conditions can be defined to balance risks among the data center customer, utility and other customers. Similarly, under collateral requirements, the data center customer either gives the money to the utility to hold until the conditions for return are met or puts the money in an independent trust. Proof of credit is another way to demonstrate financial capabilities, but no money changes hands between the customer and utility or RTO/ISO under those mechanisms.

During Customer Operation

Established industrial or commercial rate structures provide a straightforward way to charge new data centers for their electric service within the normal ratemaking process. Commissions can change existing rate structures, and several states have created new large load customer classes. In addition, riders may be applied to cover certain costs to a defined group of customer bills if a utility commission has authority to impose a rider, which could occur inside or outside the traditional ratemaking process. Special contract payments are bespoke by definition and typically must be approved specifically by a state utility commission. These special contracts may or may not preclude the addition of riders or other new payments from the customer over the course of the special contract.

Any of these forms of ongoing customer financial payments can be composed of multiple billing determinants, or types of charges. Customer charges apply to customers regardless of usage, generally charged monthly. Within a customer class, tiering and other features

can lead to different customer charges across customers. Energy charges include many different forms of per-kWh charges, which can vary by month, multihour time period or increments as small as five or 15 minutes to match wholesale markets. Unlike residential customers, nearly all industrial customers have a demand charge, denominated in per-kW terms. A demand charge can be a simple individual customer noncoincident peak demand reading during a billing period, but many more sophisticated options are also available. Industrial rates often include even more technically complex rate components, such as penalties for power factor deviations.

Nearly every newly developed tariff for data centers in recent years has included some combination of a demand ratchet, a minimum bill or a take-or-pay provision. For small customers, utilities update each component of the bill (e.g., kWhs consumed) each monthly billing cycle, but for large industrial customers, ratchets, which often lock in a billing determinant at the highest level from the previous year, and minimum requirements are common. Such structures protect other customers by preventing these customers from lowering their financial contributions but can lead to overconsumption to match the minimum requirements. Minimums and ratchets can be narrowly applied to individual components of a bill, which is how a typical demand charge ratchet works. But minimum bills and take-or-pay provisions are often broader and cover an entire bill.

Finally, data center customers can make special arrangements to procure incremental generation for some or all of their energy supply needs, but the mechanisms depend on the regulatory framework. In vertically integrated jurisdictions, the data center customer and the utility must agree on a supply arrangement, which the state utility commission reviews and approves. In fully restructured jurisdictions, the data center customer has more flexibility to find a retail supplier and generation company willing to build new resources. The actual new sources of supply can vary, from large-scale generation facilities far from the customer to demand-side resources in the community hosting the data center. The addition of new resources can curb market price impacts, but details depend on the load patterns of the data center and the new supply resources.

After Customer Service Termination

Large load tariffs and special contracts each typically have minimum terms that bind the data center customer to pay bills until the expiration of that term. If a data center customer chooses to terminate its electricity service prior to the expiration of that term, the customer is obligated to pay an exit fee or early termination fee.[51] In common practice, this fee covers a portion of the revenue that the customer would be paying over the remainder of the agreed-upon term. Instead of paying an exit fee, customers may be able to assign or reassign their obligations to other customers at the time of facility shutdown.

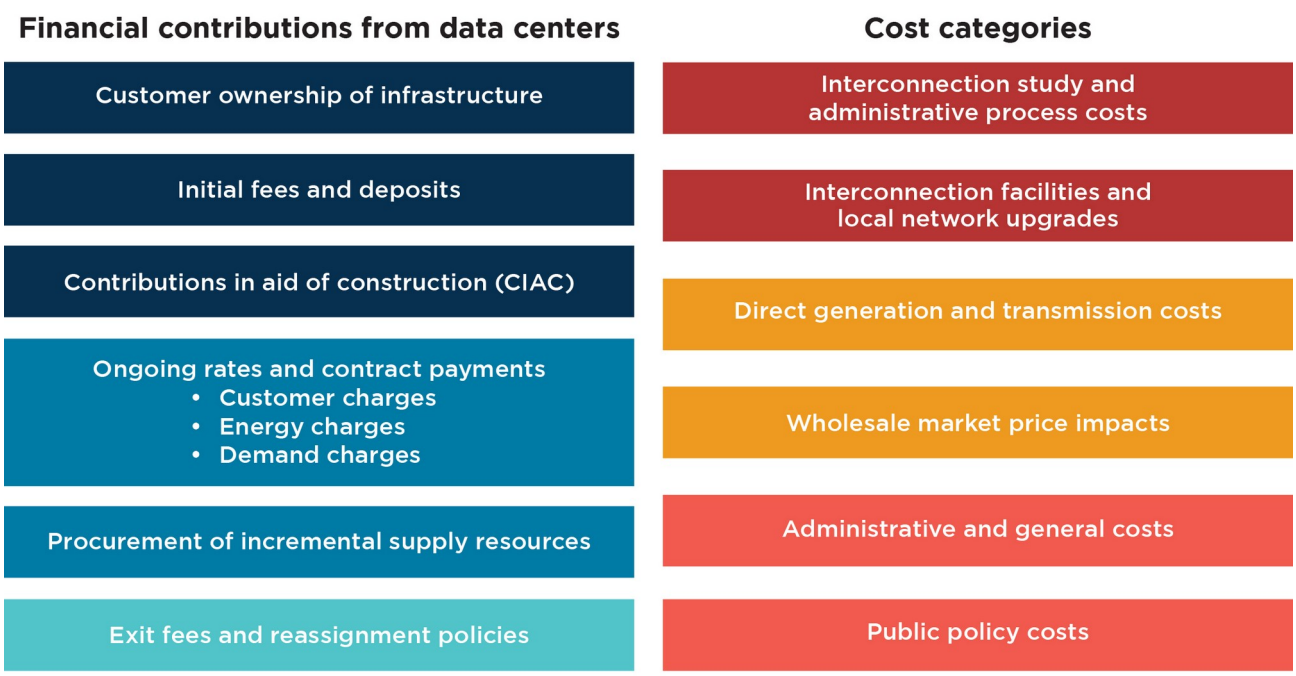
[51] Exit fees can be considered anticompetitive because they inhibit customer choice. At least two countervailing arguments are applicable to data centers. First, the size of the investments to support data center customers is unprecedented and thus otherwise would pose an extraordinary risk to other ratepayers and shareholders. Second, if there is an explicit contract, this can be considered a form of liquidated damages for breach and early termination.

The exit fee may vary by year or month from customer interconnection and may be tiered by the notice time given to the utility or other conditions. Exit fees can be calculated generically or based on the cost of specific investments and expenses. An exit fee provision may also expire at the end of a commitment term. At the time an exit fee is paid, the utility and relevant regulator must identify the relevant accounting categories that the exit fee is being applied to, reducing the future revenue requirements that need to be recovered from other customers. Risk of bankruptcy is greater if a special corporate subsidiary owns and operates a data center instead of the corporate parent, which has more financial resources.

D. Cost Allocation Levers Across Key Regulatory Cases

With a grounding on the costs new data centers cause and the life cycle of revenues from these customers, a comparison of the two is now possible. The relevant categories are shown below in Figure 7. Potential stranded costs are not specifically shown in this figure because they are a subset of the electric system costs shown in other categories.

Figure 7. Categories of Financial Contributions and Electricity Costs



Note: The size of the boxes is not intended to convey the magnitude of the financial contribution or cost.

In this figure, the previous discussion of broader generation and transmission costs has been split into two: (1) directly regulated generation and transmission costs and (2) market price impacts. This reflects the distinctions across regulatory frameworks, as well as the fact that additional measures to mitigate market price impacts are possible outside of strict

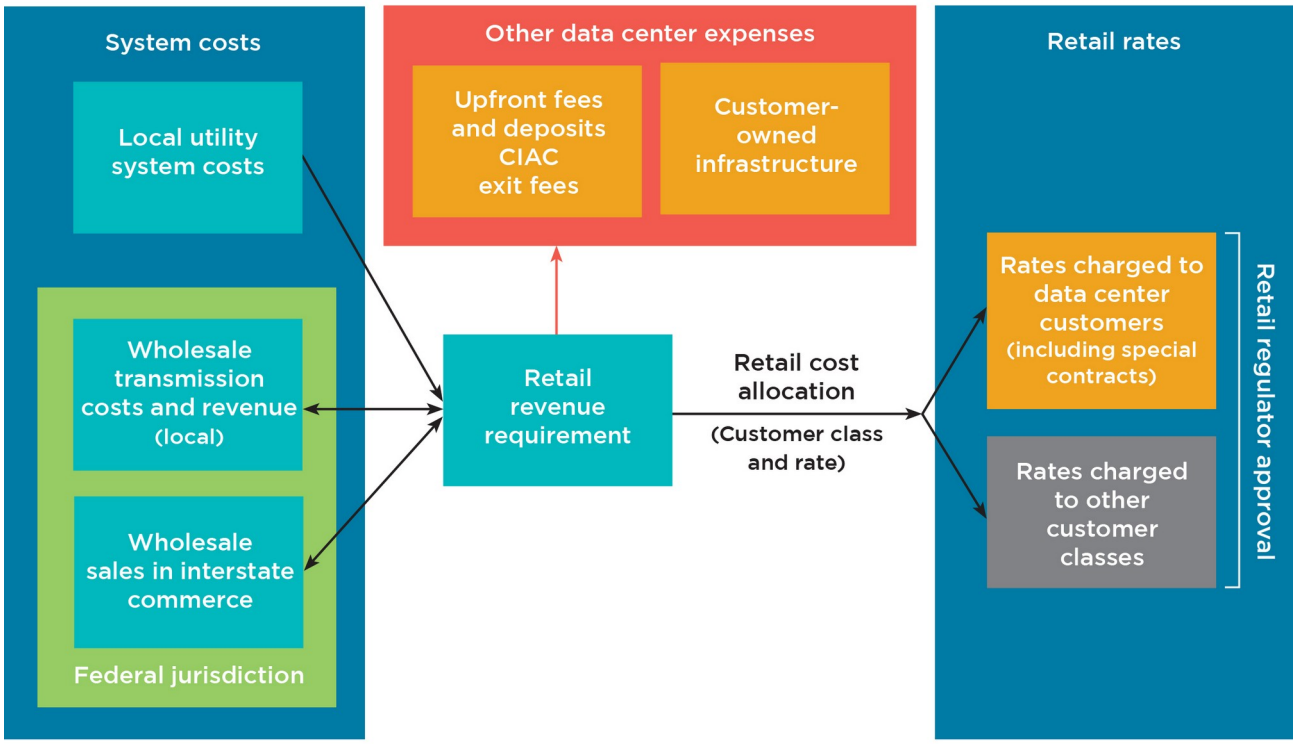
cost allocation frameworks. Two cost categories, administrative and general (A&G) costs and public policy costs, should be considered separately from core electric system costs. These are cost categories that must be shared fairly by all customers. Incremental billing and customer service costs may be incurred by utilities to serve new data center customers. Other A&G costs are incurred to support all customers and all utility functions. Public policy costs are incurred to serve different goals, including energy efficiency programs designed to pursue least-cost procurement and low-income support programs designed to improve equity and affordability.

Ultimately, the balance of impacts in each jurisdiction and utility service territory is an empirical question. We can now turn to the cost allocation levers where regulators and policymakers can change current policies that dictate the split of overall costs between data center customers and other customers. Ideally, the costs charged to data centers will be proportionate to the costs data center load growth causes, with equitable sharing of A&G costs and public policy costs. Figures 8 to 10 are illustrative for each of our cases, and do not represent every detail or variation.

Case 1: Vertically Integrated Utility Without RTO Membership

Figure 8 below shows a simplified cost allocation framework for a vertically integrated utility without RTO membership. The orange boxes represent financial contributions from data centers. The core flow chart begins with all electric system costs on the left and ends with retail customer rates on the right.

Figure 8. Simplified Cost Allocation Structure for Vertically Integrated Non-RTO Utilities



Note: The separate box for "rates charged to data center customers" does not necessarily indicate a separate data center rate class but is an illustration of the zero-sum nature of the relevant cost allocation choices.

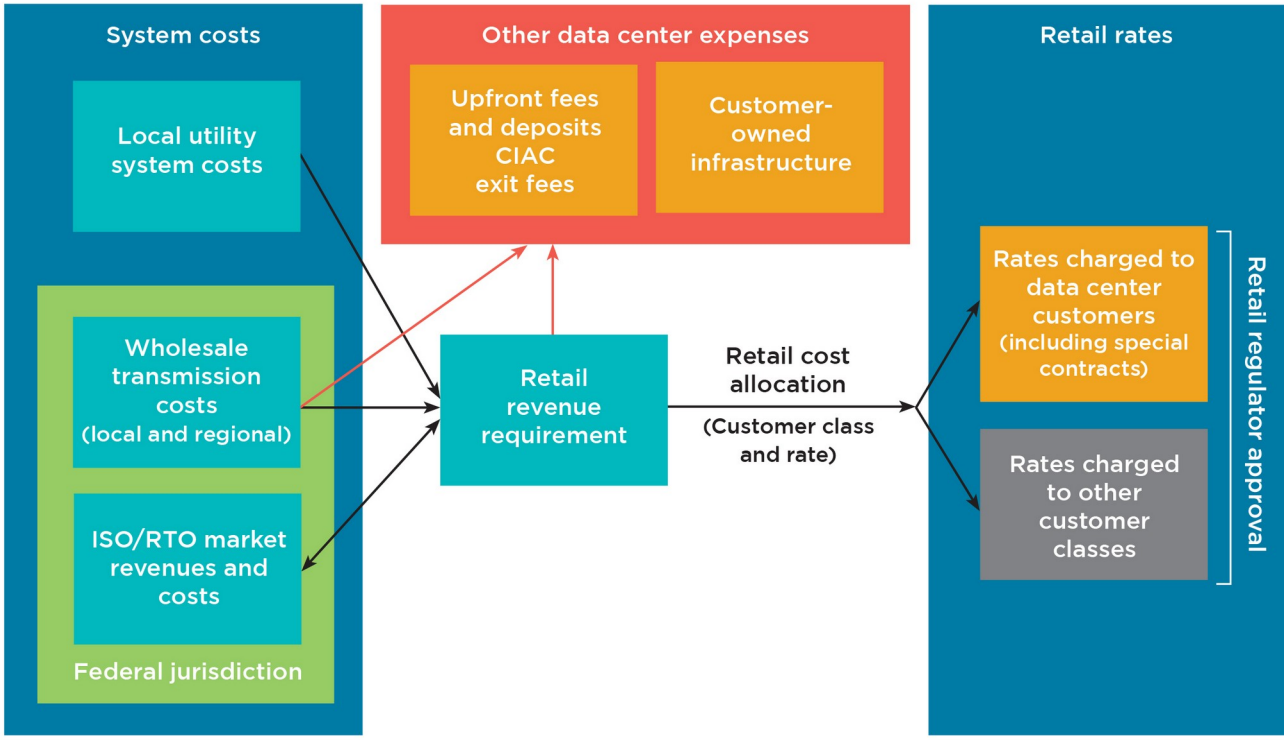
On the left-hand side, we show the different categories of electric system costs that make up the retail revenue requirement. In this context, wholesale transmission rates and wholesale sales can either be a net addition or deduction from the revenue requirement, as represented by double sided arrows. In the upper middle, the expenses and investments covered by fees and contributions in aid of construction are deducted from utility costs and do not end up in the revenue requirement. Similarly, customer-owned infrastructure is not a utility cost, so that sits separately from the flow chart of utility costs to customer rates.

For a given revenue requirement, the retail regulator oversees retail cost allocation, which determines the final split between the cost responsibility of data centers and that of other customers. While not depicted in the figure, this can take place through multiple proceedings and mechanisms. Key decisions are made in rate cases, but implicit or explicit cost allocation decisions are also made in the structure of special contract approvals and fuel and purchased power adjustment clauses.

Case 2: Vertically Integrated Utility with RTO Membership

Figure 9 below shows a simplified cost allocation framework for a vertically integrated utility with RTO/ISO membership. The orange boxes represent contributions from data centers.

Figure 9. Simplified Cost Allocation Structure for Vertically Integrated Utilities with RTO Membership



Note that the separate box for "rates charged to data center customers" does not necessarily indicate a separate data center rate class; it is an illustration of the zero-sum nature of the relevant cost allocation and rate choices.

All electric system costs are shown on the left-hand side, with wholesale transmission rates and wholesale market costs and revenue within RTO/ISOs and FERC jurisdiction. Together with the fully state-jurisdictional local utility system costs, this forms the full retail revenue requirement. While electricity market costs and revenue can either be a net addition or deduction from the revenue requirement in this context, wholesale transmission rates are now typically a cost item for retail customers. In the upper middle, customer-owned infrastructure is not a utility cost, so that sits separately from the flow chart of utility costs to customer rates. Fees, deposits and CIAC also sit in the upper middle. These charges can either be FERC jurisdictional from RTOs and transmission owners or state-jurisdictional through the retail utility, as shown by the two red arrows.

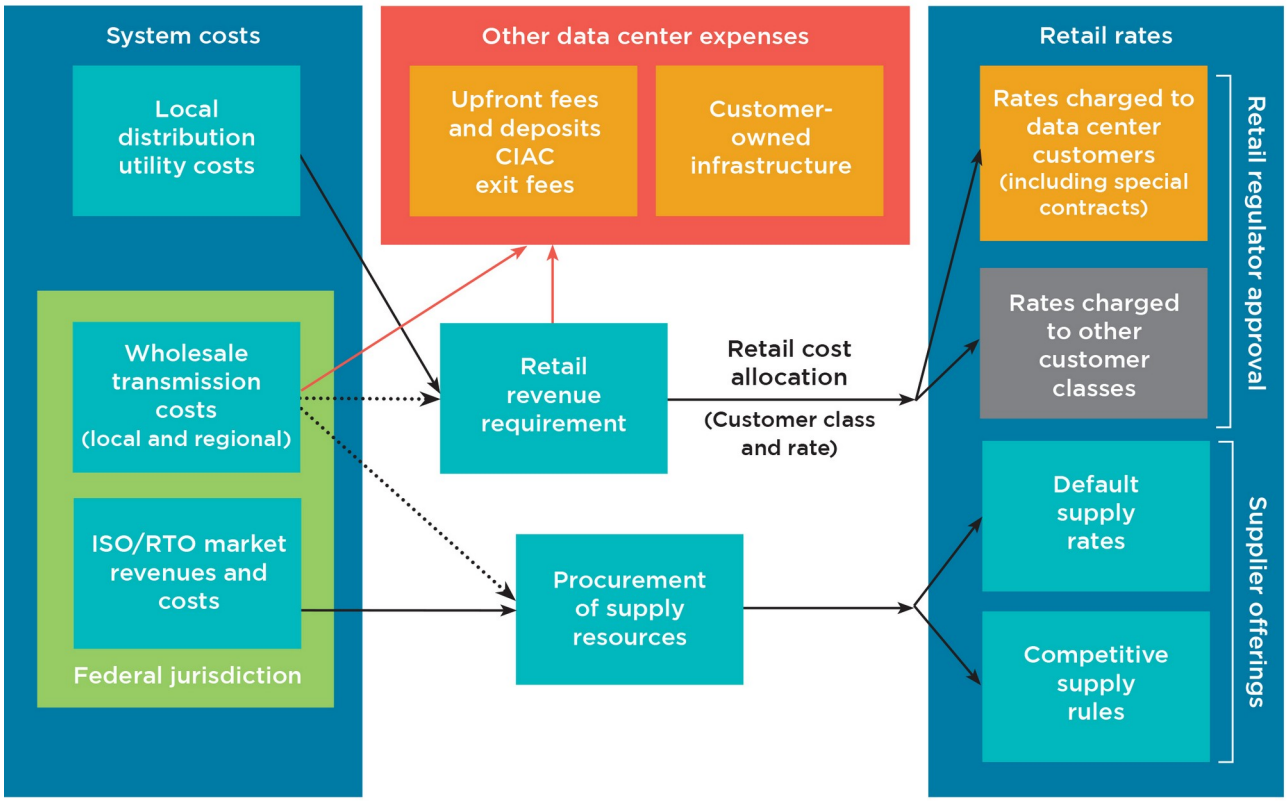
For a given revenue requirement, the retail regulator oversees retail cost allocation, which determines the final split between the cost responsibility of data centers and that of other customers as indicated on the right-hand side of the figure. Again, key decisions are made

in rate cases, special contract approvals, fuel and purchased power adjustment clauses and other proceedings.

Case 3: Fully Restructured Jurisdiction with Retail Supply Choice

Figure 10 below shows a simplified cost allocation framework for a fully restructured jurisdiction. The orange boxes represent contributions from data centers, but in this context data centers and other customers also have a choice with regards to supply rates.

Figure 10. Simplified Cost Allocation Structure for Fully Restructured Jurisdictions



Note that the separate box for "rates charged to data center customers" does not necessarily mean a separate data center rate class; it is an illustration of the zero-sum nature of the relevant cost allocation choices.

Once again, all electric system costs are shown on the left-hand side, with wholesale transmission rates and wholesale market costs and revenue within RTO/ISOs and FERC jurisdiction. In the upper middle, customer-owned infrastructure is not a utility cost, so that sits separately from the flow chart of utility costs to customer rates. Fees, deposits and CIAC also sit in the upper middle. These charges can either be FERC jurisdictional from RTOs and transmission owners or state-jurisdictional through the retail utility, as shown by the two red arrows.

While the distribution revenue requirement always goes through traditional retail cost allocation, jurisdictions differ in the treatment of transmission costs at the retail level as

shown by the two dotted lines. In some RTO/ISOs (e.g., ISO New England), wholesale transmission costs are billed to distribution companies and treated as a retail revenue requirement that is subject to traditional ratemaking and cost allocation. In other jurisdictions (e.g., portions of PJM), however, wholesale transmission costs are billed to load-serving entities. This includes competitive retail suppliers as well as electric distribution companies in their role as default suppliers. This means that retail transmission costs are a bypassable charge rolled into supply rates.

The prevailing practice in fully restructured jurisdictions is to treat all wholesale energy and capacity market costs as bypassable supply costs, as indicated by the solid line from wholesale market costs to generation supply costs. In principle, however, it is possible to handle some wholesale market costs as non-bypassable and treat them as a traditional revenue requirement, although not shown in this figure.

For the distribution revenue requirement and the portions of wholesale transmission costs and wholesale market costs treated as a non-bypassable cost, the retail regulator oversees retail cost allocation, which determines the final cost split between data centers and other customers for traditionally regulated costs. On the bottom right is generation supply rates, which are not subject to traditional retail ratemaking. Customers often have a choice between default supply offerings from their electric distribution company and competitive supply offerings from other retail providers.

V. Practical Reforms to Consider

Policymakers have explored a variety of options to respond to concern about cost shifting from data centers to households. The White House's March 2026 Ratepayer Protection Pledge claimed to "guarantee that data centers' energy needs will not increase household electricity costs for American citizens."[52] While the pledge was initially signed by the seven largest technology companies, many state governors and utilities have now signed the White House pledge or adopted their own version.[53,54] The pledge mirrors legislative and executive actions in several states, including Maryland,[55] Massachusetts,[56] Minnesota,[57]

[52] President of the United States. (2026, March 4). *Ratepayer protection pledge proclamation*. https://www.whitehouse.gov/presidential-actions/2026/03/ratepayer-protection-pledge-proclamation/

[53] Governor Gretchen Whitmer. (2026, July 15). *Gov. Whitmer launches Michigan affordable and responsible growth action plan, calls on data center companies to sign pledge* [Press release]. https://www.michigan.gov/whitmer/news/press-releases/2026/07/15/gov-whitmer-data

[54] Iverson, S. (2026, July 23). *White House expands ratepayer protection pledge to include utilities, governors.* RTO Insider. https://www.rtoinsider.com/137313-white-house-expands-ratepayer-protection-pledge/

[55] Next Generation Energy Act, 2025 Md. Laws ch. 625, § 4-212(A)(III)(d)(2). https://mgaleg.maryland.gov/2025RS/bills/sb/sb0937e.pdf

[56] Mass. Exec. Order No. 658 (2026). https://www.mass.gov/executive-orders/no-658-establishing-requirements-for-responsible-data-center-development-and-operations-in-massachusetts-to-protect-and-support-ratepayers-communities-and-the-environment.

[57] Act relating to data centers, 2025 Minn. Laws ch. 12 (enacted as HF 16, 94th Leg., 1st Spec. Sess. (Minn. 2025)). https://www.revisor.mn.gov/bills/94/2025/1/HF/16/versions/0/

Missouri,[58] New York,[59] Oregon[60] and Texas.[61] Each of these state actions broadly warn against cost shifting, but like the federal pledge,[62] they largely leave open the question of how to convert high-level commitments into tangible ratepayer protections.

Emerging practices and actions at the state and federal level are attempting to live up to these high-level commitments. At the wholesale level, FERC has directed the six RTO/ISOs to address a range of concerns, including efforts to prevent cost shifting and improve transparency to support cost allocation at the state level.[63] As a practical matter, many state public utility commissions have opened dockets and other proceedings to review utility petitions regarding individual data centers or large load tariffs.[64] Several state commissions have pursued more comprehensive or proactive approaches, including investigations to explore large load concerns.[65] The most common approach has been for states to require utilities to include specific safeguards in special contracts or to develop targeted large load tariffs that incorporate these protections. Pennsylvania's PUC developed a model large load tariff with baseline expectations for safeguards utilities within the state should include in any large load tariff.[66]

---

[58] An act modifies and creates new provisions relating to utilities, 2025 Mo., § 393.130 (enacted as SB 5, 2025 Reg. Sess. (Mo. 2025)). https://www.senate.mo.gov/BillTracking/Bills/BillInformation?year=2025&billid=66.

[59] N.Y. Exec. Order No. 62 (2026). https://www.governor.ny.gov/executive-order/no-62-establishing-temporary-moratorium-data-centers-new-york-while-state-develops

[60] POWER Act, HB 3546, 83rd Or. Legis. Assemb., 2025 Reg. Sess., enrolled. https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled

[61] Office of the Texas Governor. (2026, June 10). *Governor Abbott directs PUC and ERCOT to shield Texans from data center infrastructure costs* [Press release]. https://gov.texas.gov/news/post/governor-abbott-directs-puc-and-ercot-to-shield-texans-from-data-center-infrastructure-costs

[62] LeBel, M. (2026, April 2). *Making ratepayer protection a reality — Part 1: How do data centers impact residential rates?* Regulatory Assistance Project. https://www.raponline.org/blog/ratepayer-protection-reality-part-1/

[63] Federal Energy Regulatory Commission (FERC). (2026a, June 18). *FERC launches aggressive targeted action to speed large load integration* [Press release]. https://www.ferc.gov/news-events/news/ferc-launches-aggressive-targeted-action-speed-large-load-integration

[64] See, for example, Ohio Utilities Commission. (2025, July 9). *PUCO orders AEP Ohio to create data center specific tariff.* https://puco.ohio.gov/news/puco-orders-aep-ohio-to-create-data-center-specific-tariff; Public Service Commission of Wisconsin, Application of Wisconsin Electric Power Company for approval of its Very Large Customer and Bespoke Resources Tariffs, Docket No. 6630-TE-113, May 21, 2026, Final Order. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=591873; Xcel Energy (2026, April 14). Petition New Large Customer Project, Docket E002/M-26-170. https://efiling.web.commerce.state.mn.us/documents/%7B2043919D-0000-CB10-BC5D-5903A66B7016%7D/download?contentSequence=0&rowIndex=79; and Reilly, S. (2026, August 27). *Georgia Power gets PSC approval for massive data center contract.* RTO Insider. https://www.rtoinsider.com/141368-georgia-power-gets-go-ahead-massive-data-center-contract/

[65] For instance, Georgia recently opened an investigation into whether Georgia Power is shifting fuel costs to serve data centers and other large customers onto other customer classes: Walker, M. (2026, July 10). Georgia regulators investigating who pays data center costs. *Macon Telegraph*. https://www.govtech.com/artificial-intelligence/georgia-regulators-investigating-who-pays-data-center-costs. The New Mexico PUC opened an investigation to evaluate grid readiness and economic development, which included an assessment of large-load interconnection requests: New Mexico Public Regulation Commission, Docket 24-00257-UT, second bench request, March 7, 2025. The Arizona Corporation Commission opened an investigation into "existing rate classifications and the possible creation of more transparent rates for data center customers and the public": Arizona Corporation Commission, In the matter of the commission's inquiry and review of the existing rate classifications and other potential issues relating to data centers, Docket No. E-00000A-25-0069, filed April 2, 2025, open. https://edocket.azcc.gov/search/docket-search/item-detail/29509. Pennsylvania's PUC opened an en banc investigation into data center impacts on the state's grid and ratepayers: Pennsylvania Public Utility Commission. (2025, March 27). *PUC launches review of grid impacts from data center growth* [Press release]. https://www.puc.pa.gov/press-release/2025/puc-launches-review-of-grid-impacts-from-data-center-growth-03272025. In response to increasing large load requests, the North Carolina Utilities Commission opened a generic proceeding in June 2025 "for the purpose of receiving information and recommendations as how to fairly and efficiently integrate large electric load additions." State of North Carolina Utilities Commission, In the matter of large electric load additions, Docket No. E-100, Sub 208, Order on June 6, 2025, initiating proceeding and requesting comments. https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=e11bad51-1ebd-4237-acf7-358c292be069

[66] Pennsylvania Public Utility Commission, Interconnection and tariffs for large load customers, Docket No. M-2025-3054271, May 12, 2026, Final Order, p. 42. https://www.puc.pa.gov/pcdocs/1929842.pdf

This section explores real-world examples and presents potential reforms available to regulators seeking to shore up cost allocation policies and mitigate ratepayer risks in the era of large loads. A recent report by Lawrence Berkeley National Laboratory (LBNL) examined a sample of 55 large load tariffs to identify common tariff design elements and whether adoption has increased, stayed the same or decreased since January 2025.[67] While some of these reforms include the stable and emerging practices identified by LBNL's large load tariff report, this section includes several reforms that go beyond the traditional scope of tariff proceedings and ratemaking.

A. Initial Fees and Deposits

Given their scale and approach to site development, large customers may impose larger up-front costs (like interconnection study costs) on utilities than other types of customers — even before electric service begins. In addition, many of the initial inquiries from modern large loads may be more speculative than for historical large customers,[68] jeopardizing the potential to recover these up-front costs after customers connect. To ensure funds are available to pay for up-front costs, some states now require large customers to pay initial fees or provide deposits. We explore two examples below.

Consumers Energy Interconnection Study Fee

Consumers Energy, an investor-owned utility in Michigan, explained that utility administrative costs to support large load developments are often higher than for other types of customers because "these potential customers tend to ask for information on multiple sites with multiple load scenarios, and the sites are often ones that have not been previously studied by Consumers."[69] As a result, Consumers proposed including an administrative fee in its large load tariff to cover "engineering study, study planning, project management, economic development, and rates support needed to develop a project proposal."[70] Ultimately, the Michigan PSC required Consumers Energy to charge a $100,000 administrative fee to cover interconnection study fees and other administrative costs to connect new large customers.[71] While the fee will be collected up front, it will be reconciled through additional charges or refunds to match actual costs.

ERCOT Batch Zero and Senate Bill 6 Study Fee

Earlier this year, ERCOT in Texas approved its Batch Zero process, which "groups qualified large projects that are 75 megawatts (MW) and greater into a single study so ERCOT can

[67] Frick et al., 2026.

[68] Mai et al., 2026.

[69] Michigan Public Service Commission, In the matter of the application of Consumers Energy Company for *ex parte* approval of certain amendments to Rate GPD, Case No. U-21859, November 6, 2025, pp. 12-13. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001Nipc9AAB

[70] Michigan Public Service Commission, Case No. U-21859, pp. 12-13.

[71] Michigan Public Service Commission, Case No. U-21859, p 123.

assess the full picture of future electricity demand at once, fairly allocate available grid capacity, and identify needed transmission upgrades."[72] Senate Bill 6 requires a study fee of at least $100,000 "for initial transmission screening studies."[73]

B. Updated Contribution in Aid of Construction Policies

As noted above, contribution in aid of construction (CIAC) policies represent a common pathway for utilities to protect other existing customers from the unreasonable cost of connecting a new customer. Regulators may need to review and update existing CIAC policies given the potential scale of investment to connect new large customers. At least four states have examined this issue in different ways.

Pennsylvania Model Large Load Tariff

The Pennsylvania PUC summarized the need to update CIAC policies in its May 2026 order establishing a model large load tariff:

> Given the unprecedented nature of this load growth, we find that the Commission's approach to cost allocation must adapt to shield ratepayers from socialization of costs that are properly attributed to Large Load Customers while protecting the Large Load Customer from paying for previously . . . planned improvements.[74]

Ultimately, the PUC updated Pennsylvania's CIAC policy for network improvements,[75] concluding that "if a Network Improvement would not have been needed 'but for' the interconnection of the Large Load Customer, then the costs of the upgrade should be allocated to that customer irrespective of whether other customers would benefit from it. In such instances, the [electric distribution company] should assess a CIAC for Large Load Customer additions to recover all distribution and transmission costs necessary to interconnect the new Large Load Customer."[76] Network improvements that were planned — pursuant to a commission-approved long-term infrastructure improvement plan — before the large load customer requested service are exempt.[77]

---

[72] ERCOT. (2026, June 18). *PUCT approves ERCOT's batch zero process for connecting large electricity users while protecting system reliability for Texans* [News release]. https://www.ercot.com/news/release/06182026-puct-approves-ercots

[73] An act relating to the planning for interconnection and operation of, and costs related to providing service for certain electrical loads and to the generation of electric power by a water supply or sewer service corporation, SB 6, 89th Tex. Legis. Sess., June 20, 2025, enrolled. https://legiscan.com/TX/text/SB6/id/3248460

[74] Pennsylvania Public Utility Commission, Docket No. M-2025-3054271, Final Order, p. 42.

[75] The PUC noted that "questions of CIAC and cost allocations for network upgrades are fairly settled with respect to investments that solely benefit a single customer — the beneficiary pays." Pennsylvania Public Utility Commission, Docket No. M-2025-3054271, Final Order, p. 41.

[76] Pennsylvania Public Utility Commission, Docket No. M-2025-3054271, Final Order, p. 42.

[77] Pennsylvania Public Utility Commission, Docket No. M-2025-3054271, Final Order, p. 42.

Oregon Voluntary Generation and Transmission CIAC

Also in May 2026, the Oregon Public Utility Commission approved voluntary CIAC policies.[78] Portland General Electric's (PGE) new large load tariff allows any customer with at least 1 MW of demand "to contribute up to 100% CIAC for nonshared distribution assets." In addition, over PGE's objection, customers with at least 20 MW capacity have the option "to make CIAC up to 100 percent of generation and transmission investments."[79] The PUC noted that the voluntary CIAC has the potential to speed up the customer's interconnection if a delay is due to generation or transmission constraints. By contrast, citing nondiscrimination concerns, the Pennsylvania PUC expressly declined to adopt a proposal allowing large customers to provide voluntary CIAC contributions in exchange for expedited service.[80]

Virginia CIAC Modifications

In Dominion's service territory in Virginia, Amazon requested a voluntary CIAC similar to Oregon's that would qualify a customer for expedited interconnection for large load customers.[81] The Virginia State Corporation Commission concluded that supplemental proceedings were required to evaluate direct assignment of certain transmission costs, including Amazon's voluntary CIAC proposal.[82]

As part of those supplemental proceedings, the commission required Dominion to file an updated line extension policy, including potential modifications to mandatory CIAC, for large load customers.[83] Dominion is required to utilize a net-of-revenue approach — like its existing line extension policy — to determine the CIAC required for certain capital expenditures to install new or expanded transmission facilities that serve large load customers. These prospective changes would apply only to direct connect facilities, including substations and lines connecting the customer to the bulk power system. The commission will evaluate how to address higher-order transmission costs (related to transmission investments beyond direct connect facilities), including whether a CIAC or direct assignment would be appropriate.[84]

---

[78] As noted earlier, most previous CIAC policies are a mandatory part of line extension policies for newly interconnecting customers. The voluntary aspect of these CIAC proposals is a new concept.

[79] Public Utility Commission of Oregon, In the matter of PUC of Oregon, investigation into marginal cost study treatment of costs for large customers, Order 26-154, May 7, 2026, p. 61. https://apps.puc.state.or.us/orders/2026ords/26-154.pdf

[80] Pennsylvania Public Utility Commission, Docket No. M-2025-3054271, Final Order, p. 43.

[81] Virginia State Corporation Commission, Application of Virginia Electric and Power Company for approval of a rate adjustment clause, Case No. PUR-2026-00056, June 11, 2026. https://www.scc.virginia.gov/docketsearch/DOCS/8cq601!.PDF?_sp=2aa5cbd7-92c3-4ca4-bf49-2aaa98b87d8a.1786396807509.

[82] Virginia State Corporation Commission, Application of Virginia Electric and Power Company, Case No. PUR-2026-00056, July 31, 2026, Final Order, p. 11. https://www.scc.virginia.gov/docketsearch/DOCS/8dt001!.PDF

[83] Virginia State Corporation Commission, Case No. PUR-2026-00056, Final Order, p. 12.

[84] Virginia State Corporation Commission, Case No. PUR-2026-00056, Final Order, p. 13.

California PG&E Revisions

The California Public Utilities Commission (CPUC) approved several changes to large load cost allocation frameworks on an interim basis. Specifically, Pacific Gas and Electric (PG&E) may provide expedited transmission connections to customers who voluntarily pre-fund certain transmission network upgrades.[85] These include "modifications to the existing transmission grid to integrate service to the large load customers."[86] Customers who opt not to provide 100% prefunding for these projects must wait until the CPUC issues a final order in the proceeding.[87] For other types of transmission projects,[88] large, transmission-level customers must pay an initial advance and actual costs, if actual costs exceed the advance.[89] The CPUC deferred calculations of any refunds of customer advances (for any type of transmission facility) to its final order.[90] The order to show cause that FERC issued to CAISO (California Independent System Operator) may impact the CPUC's final order on PG&E's proposals for transmission cost allocation, among other issues, in the Rule 30 docket.[91]

C. Rates and Contract Structures for Large Loads

States can also reform rate and special contract payment structures in light of large loads. This section explores examples within three categories. First, utilities in vertically integrated jurisdictions can offer customers special generation provisions that allow customers to purchase power from a specific power project or clean energy portfolio. These structures are a version of direct assignment of costs. Second, several states can and are evaluating reforms to core cost allocation methods to better reflect the costs and risks raised by large loads. Finally, differentiated service levels that allow nonfirm (curtailable) service for large loads is another tool states are exploring to protect ratepayers from incurring unnecessary costs and supporting timely interconnection for data centers.

[85] California Public Utilities Commission of the State of California, Decision 25-07-039, p. 29.

[86] California Public Utilities Commission, Decision 25-07-039.

[87] California Public Utilities Commission, Decision 25-07-039, pp. 30-31.

[88] These projects include those dedicated to providing service to a new large customer only (called type 1), substation or switching station facilities that connect large load facilities to the transmission network (type 2), of modifications to adapt the transmission network to provide service for large loads (type 3). California Public Utilities Commission of the State of California, Decision 25-07-039, p. 8.

[89] California Public Utilities Commission, Decision 25-07-039, p. 29.

[90] California Public Utilities Commission, Decision 25-07-039, p. 36.

[91] California Public Utilities Commission, App. 24-11-007, August 7, 2026, Administrative law judge's ruling seeking comments on proceeding status. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M613/K880/613880295.PDF

Special Generation Provisions in Vertically Integrated Jurisdictions

Utilities and technology companies have been exploring special tariff or contract arrangements that bring on new generation resources for the purpose of serving a large new data center. These have been motivated by a desire to cost effectively meet reliability needs, mitigate market price impacts of load growth and protect other customers from paying for these specific costs. In some cases, these generation supply provisions are also motivated by corporate commitments to reduce greenhouse gas emissions and procure clean energy (e.g., by Google[92] or Microsoft[93]).

While dedicated supply tariff offerings have typically focused more on bulk system generation resources, they could also theoretically expand to include smaller scale resources that can be implemented faster than traditional resources. For instance, utilities could allow large load customers to pay for and receive capacity from the deployment of virtual power plants. Similarly, tools that enable customers to opt for investments in advanced transmission technology rather than traditional transmission upgrades could enable faster and cheaper connections.

Nevada Clean Transition Tariff

One of the first data-center-specific models that enables the customer to pay for higher-cost assets is the clean transition tariff (CTT) proposed by Google and NV Energy. The CTT enables Google to pay for the incremental costs of acquiring specific generating resources to serve its load. For example, Google will pay the incremental cost to obtain up to 115 MW of electricity from the country's first commercial-scale enhanced geothermal project, owned by Fervo Energy.[94] NV Energy identified the Fervo facility in its integrated resource plan but did not select it because of its high price.[95]

[92] Google. (n.d.). *Driving sustainable innovation for society.* https://www.google.com/about/datacenters/cleanenergy/

[93] Hollis, B. (2024, September 20). *Accelerating the addition of carbon-free energy: An update on progress.* Microsoft. https://www.microsoft.com/en-us/microsoft-cloud/blog/2024/09/20/accelerating-the-addition-of-carbon-free-energy-an-update-on-progress/

[94] Public Utilities Commission of Nevada, Joint application of Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises, LLC for approval of an energy supply agreement, Docket No. 24-06, June 7, 2024, application pp. 2-3. https://puc-onbase.nv.gov/api/Document/AfZIjCGlGQVafMzzfqRKw0C3%C3%89FIaVOoaWqm%C3%89pzLNkxWnXTZha%C3%81anbYcV2%C3%89Bn0PVkiM3ZVglf14NJxT0nlzrKzJw%3D/?OverlayMode=View

[95] Public Utilities Commission of Nevada, Docket No. 24-06, Hank Will's direct testimony, pp. 7-8.

Google will pay a premium, fixed price for energy provided by the Fervo facility based on the rate provided in the purchased power agreement between Fervo and NV Energy.[96] During any hours where the Fervo facility's output exceeds Google's demand, NV Energy will purchase that excess at a rate at least equivalent to its short-term avoided cost.[97] For any grid-served electricity when Google's demand exceeds the output from the Fervo facility, Google will pay the same rate as if it were being served under the otherwise-applicable, fully bundled rate. Google will also contribute the "25-year average of the capacity portion of the long-term avoided costs," as well as a special administrative fee to cover costs for implementing such a complex arrangement.[98]

Minnesota Clean Energy Accelerator Charge

In Minnesota, Google and Xcel have proposed a special contract that includes funding for 1,400 MW of wind, 200 MW of solar, a 30-GWh iron-air long-duration energy storage system and a portion of Xcel's Capacity*Connect VPP program.[99] As currently proposed, Google will pay for this portfolio via a Clean Energy Accelerator Charge, but the resources will be system assets owned and controlled by Xcel for the benefit of the system as a whole.[100] In recognition of these system benefits, Xcel will award credits to Google from the Clean Energy Accelerator Charge (CEAC) portfolio for any excess capacity or energy generation above Google's load.[101] Google will pay the full annual revenue requirement for the CEAC for 15 years. If Google's energy supply agreement with Xcel terminates before Google has fully paid the 15-year revenue requirement for any asset in the CEAC, then Google must pay for the remaining asset term. Because some of the assets have lifespans longer than 15 years, Google will not pay for the entirety of these resources.

[96] For the details of calculating this price, see Public Utilities Commission of Nevada, Docket No. 24-06, Hank Will's direct testimony to the PUC of Nevada, pp. 3-6.

[97] For the price that NV Energy will pay, see ¶ 5.2.4(b) here: Public Utilities Commission of Nevada, Schedule No. CTT amended energy supply agreement among Sierra Pacific Power Company d/b/a NV Energy, and Callisto Enterprises, LLC, Docket No. 24-06014, June 20, 2025. https://puc-onbase.nv.gov/api/Document/Abwh95MeDy5iw4ZGosz0Rp11zA%C3%81sMBOoiCRS8mNCSfKeQ%C3%81M%C3%81ScHYeUnwgvihB5wLtUgHAcjNY4R8SltzcpcjMz8%3D/?OverlayMode=View

[98] Public Utilities Commission of Nevada, Docket No. 24-06, Hank Will's direct testimony, pp. 6-7.

[99] Xcel Energy. (2026, April 7). *New Large Customer Project, Docket No. E002/M-26-170* [Petition], p. 7. https://efiling.web.commerce.state.mn.us/documents/%7B2043919D-0000-CB10-BC5D-5903A66B7016%7D/download?contentSequence=0&rowIndex=26

[100] Xcel Energy, 2026, p. 6.

[101] Xcel Energy, 2026, p. 9.

Indiana NIPSCO Ring-Fencing

The Northern Indiana Public Service Company (NIPSCO) is implementing a ring-fencing model to protect customers from costs tied to data centers. Under this model, NIPSCO established a subsidiary entity named GenCo specifically to serve data centers and other large loads with a dedicated portfolio of energy and capacity resources. If properly implemented, creating a separate entity can potentially isolate the costs of new data-center-driven growth, protecting existing customers from increased prices. At the same time, NIPSCO claims that GenCo resources, which will remain grid connected with excess generation, will improve grid reliability and create savings for existing customers.[102] R Street has criticized this model, noting that GenCo's risk profile may still affect NIPSCO's credit and borrowing costs.[103]

Reforms to Core Cost Allocation Methods

Many states are exploring changes to core cost allocation methodologies that change rates to better allocate costs caused by large loads.

Wisconsin Very Large Customer Tariff

In Wisconsin, We Energies' Very Large Customer tariff includes an administrative charge to offset the utility's personnel and other administrative costs related to customers with 100 MW or more of demand.[104] The charge includes a fixed fee of $213,118 per month per customer, plus $305 per MW of customer maximum demand during the month. Each of these components will increase annually with the consumer price index.

Michigan Consumers Energy Decision

Several cost allocation issues, including direct assignment, were raised in the recent Consumers Energy large load tariff proceeding, but the Michigan Public Service Commission (MPSC) declined to rule on those issues outside of a general rate case.[105] Instead, the MPSC ordered the utility to include at least six cost allocation and rate design proposals in its next rate case, including one that directly assigns costs — including transmission, generation and distribution costs — to an individual large load customer, and one that utilizes the 12CP method in place of the current 4CP approach.[106] The PSC also required Consumers Energy to include a proposal that directly assigns these costs to the

[102] NIPSCO. (2025, November 24). *Powering Indiana's future: How NIPSCO, GenCo, and Amazon keep energy reliable and affordable.* https://www.nipsco.com/our-company/news-room/news-article/powering-indiana-s-future--how-nipsco--genco--and-amazon-keep-energy-reliable-and-affordable

[103] Hartman, D., & Chandler, K. (2026, June 26). *Powering Indiana's energy competitiveness.* R Street. https://www.rstreet.org/commentary/powering-indianas-energy-competitiveness/

[104] Public Service Commission of Wisconsin, Docket No. 6630-TE-113, Final Order, p. 29.

[105] Michigan Public Service Commission, Case No. U-21859, pp. 114-115.

[106] The 12CP method is based on the system peak hour in every month, while the 4CP method is typically based on the system peak hour in the four summer months.

large load customer rate class, rather than the individual customer.[107] Separately, the PSC has recommended that the state legislature change a state statute that dictates certain cost allocation treatment of generation costs and allows the MPSC to develop "rate design approaches that better reflect cost causation principles" in the current environment.[108]

Oregon POWER Act

In 2025, Oregon passed the POWER Act,[109] which requires utilities to create a rate class for data centers[110] that is "separate and distinct" from classes for other commercial or industrial retail customers. The law requires any data center tariff to either allocate the costs to serve data centers "in a manner that is equal or proportional to the costs of serving the class" or directly assign the costs of serving an individual data center to that customer.[111] The tariff must also mitigate the risk of other classes of retail customers "paying unwarranted costs," including costs to meet load requirements resulting from the provision of service to the data center.[112]

In the first implementation of the POWER Act, the Oregon Public Utilities Commission (OPUC) approved a large load tariff for Portland General Electric (PGE). This large load tariff introduces two new methods to allocate growth-related costs to the customer classes driving that growth. In the first method, PGE will use a "peak growth modifier" method to identify incremental, growth-related fixed generation and transmission investments made in the prior three years.[113] Notably, investments in renewable energy will only be considered growth related when they are needed to meet load growth, but not when they are needed to comply with the state's climate policy. Investment costs will remain in the peak growth modifier "until it is demonstrated that system usage no longer supports the allocation."[114]

In the second method, PGE's "energy growth modifier" will ensure that net variable power costs due to growth are proportionally assigned to the customer class causing that growth. As approved for 2027, PGE will measure each class's proportionate share of the increase in load from one year to the next and allocate net variable power costs based on that

[107] Michigan Public Service Commission, Case No. U-21859, pp. 114-115.

[108] Scripps, D., chair. (2026, July 16). *Commission recommendations on affordability and reliability* [Letter to Governor Whitmer]. Department of Licensing and Regulatory Affairs, Public Service Commission, State of Michigan, p. 9. https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/activity/07162026_MPSC_Affordability_Letter_to_Governor_Whitmer.pdf

[109] POWER Act, HB 3546.

[110] While it does not refer to data centers, the act specifies the new tariff will apply to "large energy use facilities" that use 20 MW or more and are primarily engaged in providing services described under North American Industry Classification Code 518210, which includes "computing infrastructure providers, data processing, web hosting, and related services." HB 3546 § 2(1)(d).

[111] POWER Act, HB 3546 § 2(2)(a).

[112] POWER Act, HB 3546 § 2(2)(c). The act also requires the data center tariff (and any special contract with a data center) to include a minimum 10-year term, obligate the data center customer to pay a minimum amount or percentage of the projected electricity usage for the duration of the contract and include "any other conditions the commission may require in the public interest." HB 3546 § 5(1)(b).

[113] For details on calculating the peak growth modifier, see page 29 in Public Utility Commission of Oregon, In the matter of Portland General Electric Company, investigation into marginal cost study, Docket No. UM 2377, February 4, 2026. https://edocs.puc.state.or.us/efdocs/HBC/um2377hbc343621028.pdf

[114] Public Utility Commission of Oregon, Order 26-154, p. 20.

proportion.[115] While the OPUC approved this methodology for PGE's 2027 annual update tariff, it left the door open for how to address the energy growth modifier in future years.

Arizona Public Service Extra High Load Factor Proposal

Like PGE, Arizona Public Service (APS) has proposed a new cost allocation method that aims to allocate growth-related costs to the customer classes causing that growth.[116] As part of its ongoing rate case,[117] APS recognized that new generation resources are "inherently more costly than existing resources" and that load growth is concentrated among its Extra High Load Factor (XHLF) schedule customers. To avoid shifting costs to existing customers, APS proposed a new cost allocation method: APS will first identify whether new resources will replace retiring generation, which is assumed to serve existing customers; any remaining new resources will be assumed to be serving growing load.[118] APS will allocate costs for those remaining new generation resources to customer classes based on their contribution to load growth.

Virginia Retail Transmission Allocation Adjustments

In response to a 2025 Virginia State Corporation Commission (SCC) order, Dominion explored several new methodologies for allocating transmission costs as part of proposed changes to its Rider T1 (a line-item charge to recover transmission costs). The SCC ultimately approved Dominion's proposal for an amended 12CP methodology. The first amendment is to include "a forecast adjustment to align the customer class level allocation determinants with the expected customer billing units" for the test year.[119] The second amendment is to incorporate a minimum-demand adjustment that applies minimum-demand charges of 85% of a large load customer's contract demand. According to Dominion's calculations, this amended 12CP method reduces the monthly bill increase by 67.5% for a typical residential customer (someone using 1,000 kWh)—from an increase of $2.90 to an increase of $0.94.[120]

Interruptible Tariffs and Nonfirm Service

Load flexibility represents a potential win-win for states facing significant demand growth: It may enable faster connection of data centers while avoiding grid upgrades and

[115] Public Utility Commission of Oregon, Docket No. UM 2377, testimony of Jaki Ferchland and Isaac Barrow, pp. 16-17. See also Public Utility Commission of Oregon, Order 26-154. pp. 29-30.

[116] Arizona Corporation Commission, In the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, Docket No. E-01345A-25-0105, June 13, 2025. https://docket.images.azcc.gov/E000044763.pdf?i=1755801206426

[117] As of this writing, the proceeding is still ongoing. The evidentiary hearing concluded in late July and party briefing was completed in September 2026.

[118] For APS-owned generation, APS will assign an ELCC to retiring generation resources, then subtract that amount from the new generation resources to determine how much APS-owned generation is due to load growth.

[119] Virginia State Corporation Commission, Case No. PUR-2026-00056, Final Order, p. 6.

[120] Virginia State Corporation Commission, Case No. PUR-2026-00056, Final Order, p. 7.

safeguarding reliability for existing customers.[121] A data center can be flexible on a temporary basis, until requisite upgrades are completed. Or a more powerful alternative would be a data center that remains flexible throughout its lifespan, which could avoid certain upgrades or investments entirely and result in substantial cost savings over the long term. Load flexibility can also reduce cost and risk. If properly incorporated into utility planning, flexibility may mitigate overbuilding risk.[122] Well-managed load flexibility can also increase utilization of existing resources, which reduces costs to all customers by spreading fixed costs over more users. Furthermore, flexibility can also be achieved through customer-sited storage and generation, even if the end uses themselves are not routinely flexible.

Load flexibility can be encouraged through a range of service options. Many utilities offer voluntary economic tariffs or programs to encourage large commercial and industrial customers to reduce their demand during periods of grid stress. States could strengthen these programs by making participation mandatory for some customer classes. Nonfirm service goes beyond interruptible tariffs. Unlike firm service, which intends to be available 24/7, even under adverse conditions,[123] nonfirm service recognizes that a customer will be curtailed based on system constraints.[124] As a trade-off for quick connection, customers would receive interruptible or nonfirm service, where they are first in line for curtailment during periods of high load. Disconnection would occur ahead of other demand-side programs, and no compensation would be offered to the customer. Once network upgrades are completed, the customer would have the option to convert to firm service. While firm service has been the default traditionally, FERC, states and system operators are exploring nonfirm and interruptible service options.[125]

Idaho Speculative High-Density Load Tariff

In 2024, the Idaho PUC approved a Speculative High-density Load (SHDL) tariff to manage risks around cost shifting and stranded assets related to mobile cryptocurrency miners. In addition to system upgrade costs and higher rates, this tariff provides interruptible service to large load customers. Participation in the SHDL tariff is required for customers with demand in excess of 1 MW for at least two of the last 12 billing periods. Customers must consent to being remotely disconnected for up to 10 hours at a time and up to 225 hours

[121] Norris, T. H., Profeta, T., Patino-Echeverri, D., & Cowie-Haskell, A. (2025). *Rethinking load growth: Assessing the potential for integration of large flexible loads in US power systems* [Report NI R 25-01]. Nicholas Institute for Energy, Environment & Sustainability. https://nicholasinstitute.duke.edu/publications/rethinking-load-growth. While this study identified significant potential system benefits from various assumed levels of flexibility, it doesn't address the extent to which data centers can be flexible and how any flexibility would be implemented and enforced. EPRI's DCFlex Initiative is developing answers to the former; state policymakers and regulators could define the latter.

[122] If data centers can avoid exacerbating system peaks, they are less likely to drive substantial infrastructure expenditures that could become stranded if load fails to materialize or is later shut down.

[123] U.S. Energy Information Association. (n.d.). *Glossary.* https://www.eia.gov/tools/glossary/index.php?id=Firm%20power

[124] Davis, C., Odom, C., Pandey, S., Mooney, M., & Walmsley, A. (2026, January). *Flexible grid connections implementation guide,* p. 5. Charged. https://chargedinitiative.org/wp-content/uploads/2026/01/CHARGED-Flexible-Grid-Connections-Implementation-Guide.pdf; and Kahrl & Frick, 2026.

[125] RTO Insider. (2026, Oct. 21). *FERC Tech Conference Explores the Nitty Gritty of Data Center Flexibility*. https://www.rtoinsider.com/149155-ferc-tech-conference-explores-nitty-gritty-data-center-flexibility/

per year. Interruptions will only occur during specific hours on business days between June and September, and customers are compensated for any interruptions on a per-kW per hour basis.[126]

Arkansas Large Power High Load Density Tariff

At the end of 2023, the Arkansas PSC approved a Large Power High Load Density service to manage risk around cryptocurrency mining facilities within Entergy's service territory. The justification for this mandatory industry-specific tariff focused on the facilities' high demand, lack of credit history and ability to "relocate quickly in response to short-term economic signals."[127] A key feature of the service is that it is mostly interruptible, except that the customer can designate up to 10% of contracted demand for firm service. For the interruptible service, customers can choose between two options, with a variable number of interruptions per year and different warning periods before curtailment. Customers are not directly compensated for interruptions; instead, compensation is reflected in a discounted rate for the interruptible portion of demand.

RTO/ISO tariffs

In June 2026, FERC approved the SPP (Southwest Power Pool) nonfirm service option for large loads. To enable faster interconnection, SPP created an "as-available" transmission service called Conditional High Impact Large Load Service (CHILLS). Under this framework, new large customers may to opt to connect to the grid before necessary network upgrades are completed or additional resources are developed, but they will receive nonfirm transmission service until those upgrades or resources are obtained.[128] SPP will provide customers taking CHILLS with available transfer capability beyond what is needed to serve its firm customers. During emergency events or when the transmission system is otherwise constrained, SPP will curtail CHILLS customers;[129] customers could rely on their own contracted or onsite generation or storage during these events.[130] The CHILLS option is intended to be an interim bridge to firm service and will be available to customers for up to seven years.[131] SPP has also developed a Load Limited Resource Interconnection Service, which enables colocated generation facilities paired with large

[126] Idaho Public Utilities Commission, Schedule 20: Speculative high-density load, IPUC No. 30, Tariff No. 101, January 2024. https://docs.idahopower.com/pdfs/AboutUs/RatesRegulatory/Tariffs/20.pdf

[127] Arkansas Public Service Commission, Large Power High Load Density Service (LPHLDS), Docket No. 23-070-TF, Order No. 4, December 31, 2023. https://www.entergyarkansas.com/wp-content/uploads/2024/11/eal_lphlds.pdf

[128] Federal Energy Regulatory Commission (FERC). (2026b). *Filing description for accession number 20260605-3090,* 195 FERC ¶ 61,196. eLibrary. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260605-3090&optimized=false&sid=24a2fbeb-d89b-422e-8d34-17335287dddc

[129] The CHILLS framework builds upon the High Impact Large Load service (HILLs), which requires, among other things, that SPP be able to remotely disconnect a large load from the transmission system. FERC, 2026b, pp. 5-6. CHILLS customers will have equal curtailment priority to SPP's monthly nonfirm point-to-point customers.

[130] RTO Insider. (2026, June 9). *FERC OKs SPP's non-firm service for large loads*. https://www.rtoinsider.com/134067-ferc-oks-spp-non-firm-service-large-loards/

[131] FERC, 2026b, p. 9.

loads to connect to the grid more quickly, subject to limitations on exports back to the grid.[132]

PJM proposed its own version of limited service for large loads, called the Interim Resource Adequacy Service (IRAS).[133] The IRAS was designed to address limitations on new large loads that do not bring their own new power supply,[134] but FERC rejected the proposal as intruding on state authority and potentially discriminating against large loads.[135] FERC accepted PJM's proposal to create a large load registry that will be available to states to aid curtailment decisions at the state level.

D. Improved Wholesale Transmission Cost Allocation and Pricing

Data center load growth may be large enough — individually and in the aggregate — to cause significant transmission build-out at both the local and regional level. Changes to both data center customer-specific wholesale cost allocation and more generally to wholesale transmission cost methodologies may be necessary or helpful to prevent cost shifting to other customers. This section explores current efforts and options to address these challenges at the wholesale level. In addition, improvements to contributions in aid of construction policies discussed above are relevant for transmission-interconnected data centers.

FERC RTO/ISO Show Cause Orders

The most significant federal government action to date came in June 2026 from FERC. The Department of Energy requested that FERC regulate data centers seeking to connect directly to the transmission grid, but FERC declined to pursue a nationwide rule or dictate specific interconnection requirements.[136] Instead, FERC issued a series of tailored "show cause" orders requiring each of the six FERC-jurisdictional RTO/ISOs to demonstrate how their existing tariffs address five key areas:

[132] Federal Energy Regulatory Commission (FERC). (2026c). *Filing description for accession number 20260114-3109*. eLibrary. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260114-3109&optimized=false&sid=b53a03c0-5a4d-4f30-9ed8-82fd4a97365f at

[133] PJM. (2026). *A reliability framework for rapid large load growth.* https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interim-resource-adequacy-service-proposal.pdf.

[134] Unlike SPP's opt-in CHILLS program, the IRAS would have been mandatory for utilities and other load-serving entities that fail to bring enough new capacity to offset the combined peak demand from new large loads. During emergencies or other periods of grid stress, PJM would notify utilities to reduce or transfer the demand from these large customers ahead of any reductions to traditional customers, including residential. PJM would not cut off individual customers; rather, PJM would (1) identify any zones that did not bring sufficient new capacity to offset new large loads; and (2) during emergencies, require those zones to reduce electricity demand in proportion to their area's share of new load not supported by new generation. While PJM would leave it up to utilities and states to determine how to allocate any curtailments to individual customers, PJM would create a registry of large loads that will be available to states and utilities to aid their curtailment decisions. PJM. (2026, August 13). *PJM proposes framework to connect data centers without compromising reliability, affordability.* Inside Lines. https://insidelines.pjm.com/pjm-proposes-framework-to-connect-data-centers-without-compromising-reliability-affordability/.

[135] Federal Energy Regulatory Commission (FERC). (2026d). *Filing description for accession number 20261009-3055.* eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?_sp=2aa5cbd7-92c3-4ca4-bf49-2aaa98b87d8a.1792076892120&accession_number=20261009-3055&optimized=false

[136] FERC, 2026a,

- An efficient study process for transmission to connect large loads (including a requirement to consider advanced transmission technologies)
- Cost transparency and cost-shifting protections at the wholesale transmission level
- Clear and consistent rules regarding colocation with existing generation or behind the meter generation at large load sites
- Rules allowing large loads to take flexible transmission service independent of behind the meter capabilities
- Efficient processes for studying the interconnection of generation that will be proximate to large loads

Each RTO/ISO is required to explain how current tariffs solve these issues or else propose remedies and revisions.[137] While the FERC orders focus on RTO/ISO interconnection processes, aspects of the orders may impact how RTO/ISOs allocate transmission costs at the wholesale level. Downstream, states may then choose to change their own retail transmission cost methods. In particular, the relevant transparency requirements help improve state retail cost allocation challenges by "giv[ing] state public utility commissions and other state regulators the information necessary to allow them to understand which transmission costs are caused by which transmission customers, so that they can sub-allocate these costs to the appropriate retail customers."[138] Transparency requirements, however, do not directly change wholesale cost allocation methods but may encourage substantive reform.

Allocation Methods and Pricing for Regional Cost Sharing

For RTO/ISO broad regional sharing of transmission costs, both ISO-NE[139] and SPP[140] use 12CP cost allocation and pricing, which is based on each load-serving entity's power draw during the peak demand period for each month. However, CAISO charges wholesale transmission customers for high-voltage transmission on a uniform energy ($/MWh) basis[141] and MISO uses a uniform energy basis for projects authorized through Long Range Transmission Planning.[142] ERCOT charges on a 4CP basis, using the highest hour in four summer months (June, July, August and September).

---

[137] The initial orders required filings from each RTO/ISO within 60 days, but allowed for abeyance filings to extend the deadline by an additional 90 days. Each RTO/ISO filed an abeyance request so responses are now due November 16, 2026.

[138] FERC, CAISO Order instituting proceeding under Section 206 of the Federal Power Act, para. 68. https://www.ferc.gov/media/e-10-el26-71-000

[139] ISO New England. (n.d.). *ISO Schedule 1 Regional Network Service (RNS).* https://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/schedule1-rns

[140] See slide 3: Organization of MISO States. (2022, October 19). *Cost allocation education follow-up presentation.* OMS CAPcom. https://www.misostates.org/images/stories/meetings/Cost_Allocation_Principles_Committee/2022/Item_1ac_Education_Items_from_September_-_Copy.pdf

[141] California ISO. (2025, June 1). *June 1, 2025 TAC rates based on filed annual TRR/TRBA and load data* [Table]. https://www.caiso.com/documents/high-voltage-access-charge-rates-effective-jun-01-2025.pdf

[142] MISO. (n.d.). *Long range transmission planning.* https://www.misoenergy.org/planning/long-range-transmission-planning/

Both ERCOT and SPP are currently considering changes to their methods. Changes to ERCOT's transmission cost allocation method are under consideration in an open docket at the Public Utility Commission of Texas. The most recent staff proposal in that docket is a switch to 12CP.[143] In SPP, the Cost Control and Allocation Review & Evaluation Team recently recommended the addition of an energy ($/MWh) component to its bulk regional transmission cost allocation method.[144] Methods for allocating the cost of bulk transmission are discussed at length in chapter 10 of *Electric Cost Allocation for a New Era*.[145] It is reasonable to implement an energy component to the allocation of bulk transmission system costs because transmission provides year-round benefits through the economic exchange of energy throughout the region. But, as recognized by peak-focused methods, transmission is also built for reliability purposes for meeting peak demands. Importantly, 12CP methods and 4CP methods are not necessarily exclusive. An RTO/ISO could blend an energy component, a 12CP component and a 4CP component for regional bulk transmission cost recovery, which would follow a base-intermediate-peak cost allocation structure that is sensible in many contexts.

Methods for Geographic Distinctions

Several RTO/ISOs use more granular methods for transmission cost allocation that take into account geographic distinction in the way that different areas cause, or alternatively benefit from, transmission infrastructure – beyond the distinctions that occur through energy charges or demand-based cost allocation and pricing methods. Two contrasting examples are the highway/byway method in SPP and the solutions-based distribution factor (DFAX) power flow method in PJM.

In SPP, the highway/byway cost allocation method assigns transmission above 300 kV across the full SPP footprint and transmission 100 kV and below to the specific zone where it is located; transmission between 100 and 300 kV is allocated 33% across the full region and 67% to the zone.[146] In addition to adding an energy component to cost allocation, the SPP Cost Control and Allocation Review & Evaluation Team is considering the addition of a new "regional deliverability" geographic distinction, which would fall between the definition of a zone and the full SPP region. No final recommendations have been made, but this shows how broad geographic distinctions can be reconsidered and refined.[147]

---

[143] Public Utility Commission of Texas. (2026, May 4). *Evaluation of transmission of cost recovery* (Agenda Item No. 31, Project No. 58484) [Memorandum]. https://interchange.puc.texas.gov/Documents/58484_117_1638123.PDF

[144] See SPP. (2026, September). *Cost Control and Allocation Review & Evaluation Team.* https://www.spp.org/stakeholder-groups-list/organizational-groups/cost-control-and-allocation-review-evaluation-team/

[145] Lazar, J., Chernick, P., & Marcus, W. (2020, January). *Electric cost allocation for a new era.* Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

[146] Kahrl et al., 2025, p. 6.

[147] SPP. (2026, September 16-17). *Summary of motions and action items.* Cost control and allocation review and evaluation team meeting. Evergy. https://www.spp.org/documents/77908/care%20team%20minutes%2020260916-17.pdf

In PJM, the DFAX method is used to allocate 50% of the cost of high-voltage transmission lines and the full cost of lower-voltage transmission lines to specific customer zones within the PJM footprint.[148] This method uses power flow modeling to determine the relative responsibility of different zones for each transmission line. The Maryland Office of People's Counsel (OPC), the state statutory consumer advocate, has recently challenged this method at FERC.[149] OPC contends that the DFAX method inappropriately allocates costs to Maryland ratepayers, which should be allocated instead to the neighboring regions where large load growth is causing transmission costs.

E. Options for Retail Energy Supply in Fully Restructured Jurisdictions

As noted above, data centers and other large loads pose specific challenges for retail energy supply costs in fully restructured jurisdictions. Three strategies can help address these concerns: improved hedging for default retail supply, "bring your own" generation requirements and reallocation of wholesale market costs. We discuss each in more detail below.

Improved Hedging for Retail Supply

Contracts that comprise default service tend to be short-term contracts no longer than three years in length. Entering longer-term contracts for some portion of the default service portfolio would improve price stability, though it would not necessarily reduce average rates. Doing so would also risk locking in higher prices if the market declines. To avoid retrospective prudence fights when higher prices are inevitably locked in, the PUC would need to affirm that price stability is a prudent goal. Long-term hedging can be layered into the default supply slowly to achieve a target portion of the default supply — for example, adding 10% of the mandated amount per year for five years in order to achieve 50% long-term contracts.

Default supply was intentionally designed with short-term contracts to promote retail choice, to prevent utilities from undercutting other suppliers and to avoid customers being locked into the default service. Longer-term contracts would be a hedge against market volatility but could reduce customer switching to competitive products or have other side effects. Any such trade-offs should be acknowledged if long-term hedging is to be implemented.[150]

---

[148] Rose et al. 2026, p. 18.

[149] FERC, *Maryland Office of People's Counsel v. PJM Interconnection, LLC,* Docket No. EL26-000, May 7, 2026. https://opc.maryland.gov/Portals/0/Files/Publications/Others/20260507%20-%20RTEP%20complaint%20-%20FINAL%20932.pdf?ver=g-tF-_4Avtsm8DfgEozavA%3d%3d

[150] PJM. (2026, May 6). *Powering reliability through market design.* https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2026/20260506-powering-reliability-through-market-design.pdf

PJM has identified long-term bilateral contracts between generators and default service providers as the simplest hedging option.[151] Such long-term contracts would require no new central administration. However, states may need to statutorily authorize or otherwise direct default service providers to execute contract types already available to competitive providers. A recent Grid Strategies report goes further, arguing that states should direct retail suppliers to procure sufficient capacity to meet load via long-term contracts.[152] While such long-term contracts with generators could have the added benefit of bringing more generation online, they do shift risk from one party to another.

Bring Your Own Generation Requirements

Bring Your Own Generation (BYOG) and related policies for Bring Your Own Clean Energy (BYOCE) are emerging approaches for large load customers to meet their own generation supply needs and to shield existing customers from increased energy supply costs. A BYO policy that requires supply to be matched with data center load on an hourly basis assures that incremental supply costs will be borne by the data center, rather than existing customers. With hourly matching, the new load avoids increased use of existing generation, which can result in increased marginal energy costs, and avoids increasing load during peak hours, which could require building new generation — all costs that would be borne by all customers. Practically, however, hourly matching can be difficult and cost prohibitive for data center developers. BYO load matching on an annual-consumption and peak-demand basis is another, potentially simpler way to protect existing customers. While this does not protect existing customers from every supply-related cost impact, it does shield them from the largest category of supply costs — building new power plants — and likely shields them from the vast majority of other energy supply costs, including renewable portfolio compliance costs. Existing generation owners and suppliers are not necessarily supportive of the BYO principle, as it aims to drive new generation onto the system.

The appropriate BYO policy for any state will depend on its policy goals and the degree to which it is comfortable exposing existing customers to some or all increased energy supply costs resulting from data center developments. The most straightforward BYO policies simply require data centers to bring their own supply as a condition of development. Massachusetts[153] and Pennsylvania[154] have both taken executive action to implement BYOCE policies, with Massachusetts requiring new data center load to be matched 100% with new clean energy. The New York Public Service Commission is exploring requirements for data centers to supply their own generation or storage as part of its Energize NY

[151] PJM, 2026.

[152] Gramlich, R., Coscia, C., Doying, R., Fisher, E., Goel, S., Greene, S., Hogan, M., & Kaplan, K. (2026, October). *Stabilizing consumer bills through state-driven long-term bilateral contracting.* Cleanecon. GridStrategies. https://cleanecon.org/wp-content/uploads/2026/10/GS_CleanEcon_Stabilizing_Consumer_Bills_FINAL-8.pdf

[153] Mass. Exec. Order No. 658 (2026).

[154] Pennsylvania Department of Community & Economic Development. (2026). *The Governor's Responsible Infrastructure Development (GRID) requirements.* https://dced.pa.gov/business-assistance/data-center-resources/grid-requirements/

Development proceeding (Case 26-E-0045) consistent with Governor Hochul's 2026 State of the State proposal.[155]

Other approaches to BYO policies exist, including providing expedited interconnection and faster permitting for generation.[156,157] One difficulty with expediting data center interconnection is that the matching supply cannot always be built as quickly as the data center. As discussed previously, FERC has instructed the RTOs to develop interim rules and service types. Data centers that commit to bringing their own generation can temporarily access nonfirm service until network upgrades are completed, at which point their service will convert to firm.[158]

Reallocation of Wholesale Electricity Market Costs

RTO/ISOs in fully restructured jurisdictions rely significantly on the prices and investment signals in wholesale markets to meet resource adequacy requirements and drive new investment when necessary. PJM's 2028/29 Base Residual Auction was unable to procure sufficient capacity to achieve its target reserves and risk level, likely due to the large number of data centers being built or proposed in the region. In response to this shortfall, the White House National Energy Dominance Council urged PJM to conduct a reliability backstop procurement (RBP) that would drive new generation onto the grid. The costs from this procurement can fairly be attributed to data centers, and the council instructed PJM to assure that those costs would be allocated to data centers and not to residential customers.[159]

Under the proposed RBP, PJM will allocate costs to zones in proportion to their share of the established procurement target. Zone costs will then be allocated to the load-serving entities within the zone based on a new mechanism called a reliability backstop obligation (RBO). The RBO is designed to accommodate state-established cost allocation frameworks, meaning that RBP costs can be allocated to new data centers if a state has established a corresponding framework to allocate incremental capacity costs to new data centers. If a state has not established a framework for allocating incremental capacity costs to data centers, however, RBP costs will be allocated based on existing cost allocation methodologies, effectively passing RBP costs to both new and existing retail customers.[160]

---

[155] Hochul, K. (2026). *State of the state 2026*. We Are NY, New York State. https://www.governor.ny.gov/sites/default/files/2026-01/2026StateoftheStateBook.pdf

[156] FERC, 2026a.

[157] Kahrl & Frick, 2026. See Section S4.3 here: https://eta-publications.lbl.gov/sites/default/files/2026-06/lbnl_large_loads_speed_to_power_final_1.pdf

[158] Wang, S., & Farrell, T. (2026, July 6). *Understanding FERC's large load orders.* RMI. https://rmi.org/resources/understanding-fercs-large-load-orders/

[159] National Energy Dominance Council and undersigned governors. (2026, January 16). *Statement of principles regarding PJM,* https://www.energy.gov/documents/statement-principles-regarding-pjm

[160] PJM. (2026, May 19). *Reliability backstop procurement/connect and manage* [Letter to stakeholders]. https://www.pjm.com//-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260519-pjm-board-letter-re-reliability-backstop-procurement-connect-and-manage-cifp.pdf?_sp=075cf5a5-478f-4aa0-85f7-aac51a921efe.1789744306103

This means PUCs must quickly implement frameworks to allocate costs to data centers. Such frameworks should ensure that the state is assigned an appropriate share of the procurement target, establish a cost allocation formula for new data centers and ensure that this formula allocates costs appropriately between load-serving entities, distribution companies and retail customers. Commissions will need to examine the existing statutes and regulations for any restrictions on their authority to reallocate wholesale market costs. Most likely, mandatory reallocation would occur by designating these specific costs as non-bypassable and treating the costs as a traditionally regulated revenue requirement to be allocated across customer classes.

F. Reallocation of Public Policy Costs

Recognizing that it may be challenging, if not impossible, to precisely allocate 100% of costs caused by large customers to that customer class, some states are pursuing strategies that reallocate public policy costs. These can include surcharges or taxes on certain classes of customers. We explore four examples below.

Oregon low-income efficiency and weatherization surcharge

In its recent order approving PGE's large load tariff, the Oregon PUC recognized that large loads place "unique burdens on the system and thus on other customers that, while difficult to quantify, are nevertheless real."[161] For example, the commission noted it is "difficult to isolate" the "degree to which new, very large loads are raising costs across the region by utilizing relatively scarce clean energy generation projects or limited transmission capacity." As such, the commission approved a $0.01 / kWh surcharge for PGE customers with 100 MW or more of allocated system capacity. Revenue from the surcharge will fund non-cost-effective energy efficiency, "critical home repairs" and distributed resources "to reduce energy burden for the most vulnerable customers."[162] The PUC distinguished this surcharge from an impermissible additional public purpose charge based on its structure and the use of funds.

Minnesota low-income efficiency and weatherization surcharge

In 2025, the Minnesota legislature adopted House File 16 to implement an annual fee for large data centers representing 100 MW of load or more. The annual fee structure ranges from $2 million to $5 million, depending on facility size and peak demand, and allocates those funds to low-income weatherization and energy efficiency programs.[163] Notably, data centers are exempt from paying into standard utility energy efficiency programs. The

[161] Public Utility Commission of Oregon, Order 26-154, p. 13.

[162] Public Utility Commission of Oregon, Order 26-154, pp. 2, 13.

[163] Act Relating to Data Centers, 2025 Minn. Laws ch. 12 (enacted as HF 16).

annual fees are paired with other tax exemptions and a streamlined permitting process, with the general purpose of attracting data centers to Minnesota while maintaining the state's environmental and energy efficiency goals.

Virginia electricity consumption tax

In 2026, Virginia lawmakers approved a first-in-the-nation tax on data center electricity consumption. The tax will be $0.011/kWh on all electricity consumed at each data center, effectively representing a roughly 10% increase in the electricity rate paid by data centers.[164] Revenues are capped at $600 million annually, which goes to the general fund.[165] The rest is refunded to data centers on a pro rata basis.

Massachusetts Ratepayer Protection Fund

On September 8, 2026, Massachusetts Governor Maura Healey signed Executive Order No. 658 establishing requirements for data center development and operation. Section 5 of Executive Order No. 658 requires data centers with peak electricity demand exceeding 25 megawatts to procure sufficient incremental new clean electricity generation to meet their annual electric consumption. Section 5 also requires the Massachusetts Department of Environmental Protection to establish an alternative compliance payment (ACP) mechanism for data centers that do not procure sufficient incremental clean electricity to meet their annual electric consumption. Funds collected via this new ACP mechanism shall be credited to a Ratepayer Protection Fund to mitigate the increased electricity supply costs caused by data centers that fail to bring their own clean energy or that interconnect before the procured clean energy comes online.

G. Exit Fees

Exit fees are an emerging practice to protect existing customers from cost shifts if a large customer terminates service before the end of the contract term.[166] Exit fees can mitigate the financial risk of a large customer leaving early by ensuring that the utility (and by extension, existing ratepayers) is compensated for any costs incurred to serve the customer. This could range from charging a fixed fee to charging any uncollected costs incurred to serve that customer. Many large load tariffs charge the customer the equivalent of the minimum monthly charge over a set period of time.

---

[164] Snider, S. (2026, June 23). *Virginia approves first-ever data center power tax*. Data Center Knowledge. https://www.datacenterknowledge.com/regulations/virginia-approves-first-ever-data-center-power-tax

[165] Virginia State Legislature, Data Center Consumption Tax, Budget Amendments — HB30, Item 3-5.24#1c, 2026 Spec. Sess. (Vir. 2026). https://budget.lis.virginia.gov/amendment/2026/2/HB30/Introduced/CR/3-5.24/1c/

[166] Frick, N. M., Cappers, P., Kavlak, G., Lam, L., Hledik, R., Grove, J., & Rotella, S. (2026, August). *Electricity rate designs for large loads: Evolving practices and opportunities 2026 update,* p. 15. Energy Markets & Planning, Berkeley Lab. https://eta-publications.lbl.gov/sites/default/files/2026-08/rate_designs_large_loads_2026.08.10.pdf

Evergy Kansas

In 2025, the Kansas Corporation Commission approved Evergy's proposed large load power service (LLPS) tariff structure for customers with more than 75 MW of demand and contracts of 12 years or longer. The tariff is structured with a minimum monthly bill equal to at least 80% of contracted demand.[167] The exit fee is calculated as the minimum monthly bill for every month remaining in the contract or for 12 months (whichever is larger). If the contract is terminated with less than 36 months remaining, then the exit fee is doubled for each month under 36 months.[168] There is a pressure-relief mechanism whereby the customer can shed 25 MW or 10% of demand (whichever is smaller) without a penalty, if the customer provides 24 months' notice.

This tariff was the product of 18 months of negotiation and represented unanimous agreement between Evergy, Google, the Data Center Coalition, the Citizens' Utility Ratepayer Board, the Sierra Club and others. As of August 2026, Evergy had executed five electric service agreements for data centers under the LLPS tariff.[169]

AEP Ohio

Also in 2025, the Public Utilities Commission of Ohio (PUCO) approved a tariff proposed by AEP Ohio specifically for data centers with demand greater than 25 MW. This tariff sets a monthly minimum charge of up to 85% of demand.[170] The exit fee for data center customers using this tariff is calculated as three years of the monthly minimum charge.[171] The option to exit the contract by paying this exit fee, however, does not become available to the customer until five years after the completion of any load-ramping period. Exit fees collected by AEP Ohio will be refunded to ratepayers. In cases where a viable and practical option is available, which does not impose additional costs on ratepayers, data center customers can reduce their contracted demand by up to 25% without penalty by assigning it to other data center customers.

---

[167] For specific "minimum monthly bill" calculation, see page 10 of Kansas Corporation Commission, Joint motion for approval of unanimous settlement agreement and amendment of the procedural schedule, Docket No. 25-EKME-315-TAR, November 14, 2025. https://kcc-connect.kcc.ks.gov/s/filing/a1Acr000003Dsd2EAC/tr2502489

[168] See discussion starting on slide 8: Senate Utilities Committee. (2026, January 15). *KCC Utilities Division update*. Kansas Corporation Commission. https://www.kslegislature.gov/b2025_26/committees/testimony/pdf/?apn=b2025_26/year2/senate/committees/ctte_s_utils_1/testimony/published/ctte_s_utils_1_20260115_01_testimony.html

[169] Evergy. (2026, August 6). *EVRG.OQ – Q2 2026 Evergy Inc earnings call.* LSEG Data & Analytics. https://investors.evergy.com/static-files/c97e6e9b-92bf-413a-9d71-4e2b3f6e30f4

[170] For specific "minimum demand" calculation, see the "10/23 Stipulation Column" on page 17 of Public Utilities Commission of Ohio, In the matter of the application of Ohio Power Company for new tariffs related to data centers and mobile data centers, Case No 24-508-EL-ATA, July 9, 2025. https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G09B43531I00509

[171] Vorys. (2025, July 11). *Public Utilities Commission of Ohio authorizes tariff for AEP Ohio's data center customers, requires end of moratorium on new services for data centers*. Client Alert. News & Insights. https://www.vorys.com/publication-public-utilities-commission-of-ohio-authorizes-tariff-for-aep-ohios-data-center-customers-requires-end-of-moratorium-on-new-services-for-data-centers

This tariff was decided via contested proceedings over 14 months. The PUCO ultimately sided with AEP Ohio, Ohio Partners for Affordable Energy and the Ohio Consumers' Counsel and against a competing proposal from a coalition of tech companies, data center developers and other large commercial groups. As of February 2026, AEP Ohio reports that the tariffs were working as designed to protect ratepayers from overbuilding for speculative load.[172]

Wisconsin Very Large Customer Tariff

We Energies' Very Large Customer Tariff establishes baseline terms for large load contracts. The tariff requires Very Large Customers to subscribe to the companion Bespoke Resources tariff in order to pay for incremental costs, specifically new energy and capacity dedicated to those customers (Bespoke Resources). If a customer terminates service before the Bespoke Resources enter service, the customer must pay a proportional share of the utility's incurred costs. If the termination happens after the resources are operational but before the end of the contract term, the customer must pay for the net-book value of the Bespoke Resources, to the extent those resources cannot be repurposed.[173]

[172] Nourse, S. T., VP. (2026, February 12). *Re: In the matter of the application of Ohio Power Company for new tariffs related to data centers and mobile data centers, Case No. 24-508-EL-ATA* [Letter to Jenifer French, chair, Public Utilities Commission of Ohio]. American Electric Power. https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A26B12B61453D00940

[173] Public Service Commission of Wisconsin, Docket No. 6630-TE-113, Final Order, p. 18.

VI. Conclusion and Further Research

Cost allocation issues and the many ways that load growth can lead to higher retail rates are clearly complex, as demonstrated by this report. Starting with our higher-level framework, regulators and other policymakers need to understand the incremental costs and revenues from data center load growth. From this baseline, policymakers can consider a wide range of improvements, but the options vary significantly depending on the regulatory framework. This report explores reforms that can start addressing data center cost allocation challenges. We fully expect that regulators, other government entities and stakeholders will continue to innovate in the policy areas discussed in this report.

Even in cases that appear simple, we expect significant debate about the right analysis for many quantitative questions as well as more qualitative judgments around fairness. Structural aspects of the different regulatory frameworks, however, raise broader conceptual questions. In vertically integrated jurisdictions, regulated utility generation investments expose ratepayers to risks. In fully restructured jurisdictions, current policies expose many residential ratepayers to increases in wholesale electricity market prices. Regulators and policymakers within each regulatory framework must wrestle with the small and large implications of these structural choices.

Zooming out, building a 21st century regulatory system will mean adapting government policies to the technologies of today, whether that is new clean energy resources, advanced network technologies or new sources of energy demand. Data centers pose unique concerns but also share many things in common with other sources of load growth, such as new manufacturing facilities, industrial electrification of existing fossil fuel end uses, electric vehicles and efficient electric heating and cooling.[174] The key issues for further research include topics specific to data centers and any similarly situated large loads, as well as broader issues for a future of load growth.

Better understand the costs of load growth: In a few jurisdictions, marginal cost of service studies are still required for ratemaking purposes (e.g., California), and in some other places similar studies are undertaken for energy efficiency programs and other purposes (e.g., the joint Avoided Energy Supply Cost studies in New England). A better understanding of marginal or incremental costs is necessary for many reasons. With respect to cost allocation, this information is crucial to the evaluation of whether data center customers are paying their fair share. These studies would help improve rate design as well as planning processes and other programs designed to find optimal solutions.

Clarify jurisdictional ambiguities and facilitate cooperation between FERC and states: There are several issues where jurisdictional ambiguities or lack of transparency

[174] One key distinction is that residential customers, where much of the new electric vehicle and electric heating adoption may take place, typically pay higher rates than industrial customers.

and cooperation may impede progress. The Federal-State Current Issues Collaborative,[175] hosted by FERC, with participation from state utility commissioners, is an important new forum for exploring these issues. Further collaboration and potentially legislation will be needed.

Expedite development of electricity supply: While congressional action may be possible on energy permitting issues and review timelines, there are many different actions that FERC, RTO/ISOs and states can pursue to promote and expedite development of electricity supply. This includes best practices for interconnection and the related policies for "bring your own new generation" and "bring your own clean energy."

Improve planning and load forecasting: Indiscriminate build-out, whether of generation, transmission or distribution, is too risky. Forecasting improvements must be designed to narrow uncertainties and provide sufficient lead time to find the most cost-effective investment options, whether that is new infrastructure, battery storage or customer-side resources.

Develop new pricing models for colocated load and generation: Colocation arrangements have the potential to reduce the costs of load growth on the shared electric system but raise numerous questions about the fair and efficient way to price the customer's continued usage of and reliance on the system.

Address end-of-life-cycle concerns about potential data center customer bankruptcies: Financial security, letters of credit and other measures may be necessary to avoid risks from data center bankruptcy. A corporation solely organized to own a data center facility may not have sufficient financial backing if utilities do not have recourse to a parent corporation.

[175] FERC. (2026e). *Federal-state current issues collaborative: Docket No. AD24-7-000.* https://www.ferc.gov/federal-state-current-issues-collaborative

Appendix A. Modern Regulatory Frameworks across the United States

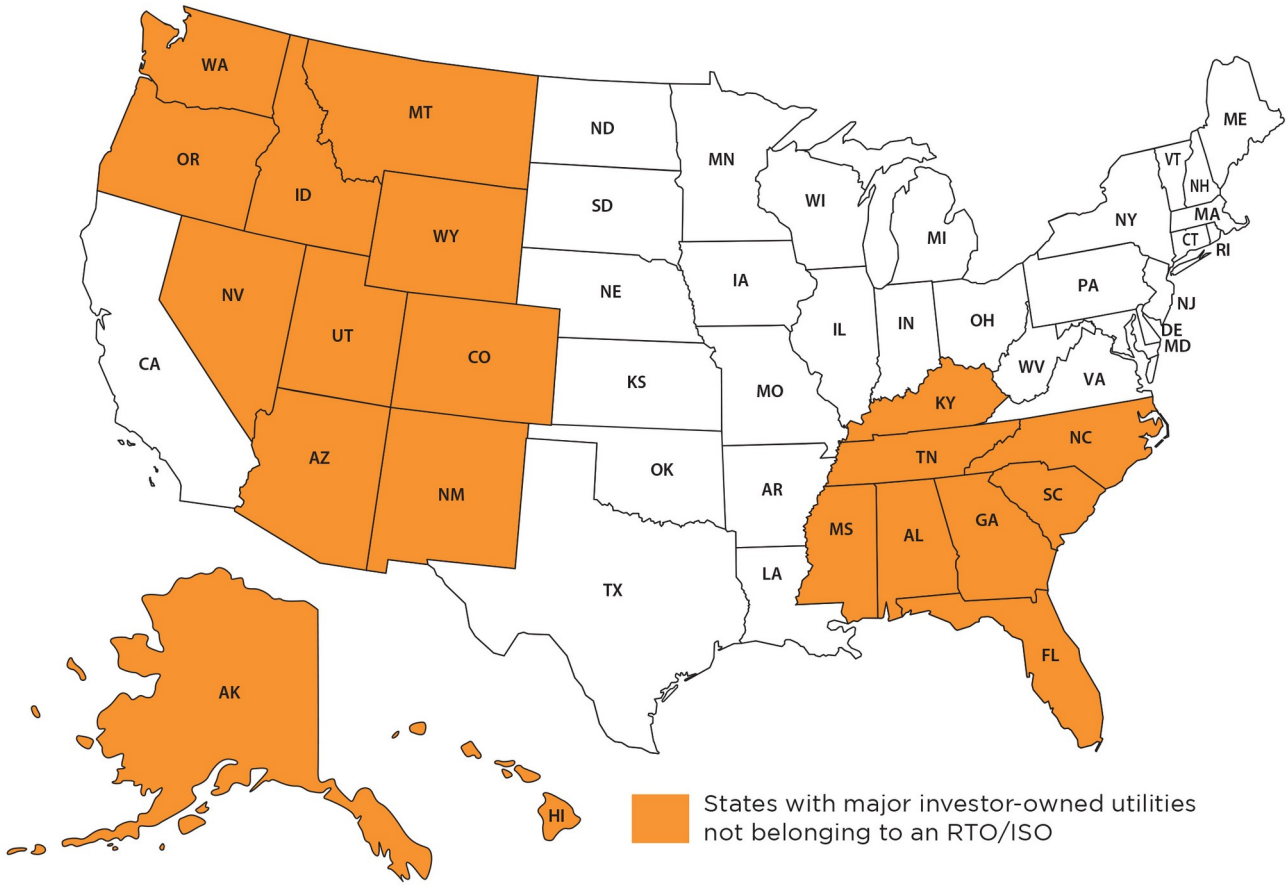
Traditional electric utility regulation in the United States started in the early 20th century as state regulation of investor-owned utilities (IOUs) under state law. This regulatory framework has changed greatly over time with major updates to federal law and many state laws. This appendix describes modern regulatory frameworks in more detail, which is helpful to understand how electricity rates work today.[176] This begins with the set of utilities that stay closest to the original regulatory framework, with vertically integrated IOUs that have not joined an RTO/ISO. In the past 30 years, many utilities have joined an RTO/ISO overseen by FERC, and many states have chosen to fully restructure their electric utilities and the regulatory framework. Many states have ended up with hybrid regulatory frameworks that combine features of the original model, such as utility ownership of generation, with wholesale markets and retail supply choice to different extents. Lastly, other utility ownership models are regulated under other paradigms, which are heavily influenced by their regional regulatory context.

Vertically Integrated Non-RTO Utilities

A significant number of jurisdictions have remained closer to the original regulatory structure, with vertically integrated utilities that own generation, transmission and distribution overseen by a state public utility commission. This is especially true in Alaska and Hawaii because the relevant federal laws have never applied there. However, in the mainland United States, states that have chosen to retain vertically integrated utilities and utilities that have not chosen to join an RTO/ISO have a federal regulatory overlay with respect to transmission and wholesale energy markets. Figure A-1 below shows the states that have one or more major IOU that has not joined an RTO/ISO.

[176] For more on federal and state jurisdiction boundaries, see Dennis, J. S., Kelly, S. G., Nordhaus, R. R., & Smith, D. W. (2016, December). *Federal/state jurisdictional split: Implications for emerging electricity technologies.* Lawrence Berkeley National Laboratory. https://www.energy.gov/sites/prod/files/2017/01/f34/Federal%20State%20Jurisdictional%20Split--Implications%20for%20Emerging%20Electricity%20Technologies.pdf

Figure A-1. States with Major Vertically Integrated Non-RTO Investor-Owned Utilities



Note: Although we have chosen to not color Texas on this map, El Paso Electric in western Texas is a traditionally regulated vertically integrated electric utility that is not a member of an RTO/ISO.

Most notably, in 1935, the Federal Power Act expanded the authority of the Federal Power Commission (now the Federal Energy Regulatory Commission or FERC) to cover "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce."[177] With respect to transmission, vertically integrated IOUs must have wholesale transmission rates that apply to other entities that use their transmission system.[178] For example, a municipal utility may contract with an independent generator, which interconnects to the IOU's transmission system and delivers energy to the municipal utility over the IOU transmission network. FERC regulates these wholesale transmission rates, which then form part of the cost structure for the municipal utility or other load-serving entity paying for transmission service.

[177] 16 U.S.C. § 824(b)(1). This same provision has additional specific exclusions for generation, distribution and transmission only in intrastate commerce. The same section also states that "such Federal regulation, however, [will] extend only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). The relevant federal statutes elaborate on the definition of these two authorities and also stipulate that FERC regulation only applies to a relevant set of defined "public utilities," which excludes government-owned utilities and cooperatives in most cases. 16 U.S. Code § 824(f).

[178] In 1996, FERC Order 888 required investor-owned public utilities who owned transmission used in interstate commerce to file Open Access Transmission Tariffs (OATTs). OATTs included wholesale rates for the use of a utility's transmission system.

For the vertically integrated IOUs themselves, there are two models for how their retail transmission rates are formed. In some jurisdictions (e.g., Portland General Electric in Oregon), the utility transmission rate base is calculated and adjudicated in the traditional state fashion. Any wholesale transmission revenue from other entities is then deducted from the state transmission revenue requirement. Alternatively, some states and utilities (e.g., Arizona Public Service) have turned more fully to FERC regulation. FERC adjudicates the full transmission rate base in proceedings where the state commission is a participant. This leads to a wholesale transmission rate that applies to other entities, but also to the IOU's usage of its own system. This leads to a wholesale transmission revenue requirement for the IOU that is then incorporated into retail rates.

With respect to wholesale sales, FERC has long overseen many forms of market purchases and sales between utilities and other entities, although certain kinds of utility energy contracts are not necessarily subject to FERC jurisdiction. The wholesale sales overseen by FERC are increasingly being structured through organized wholesale markets outside of RTO/ISO boundaries. As of 2026, many vertically integrated utilities which are not RTO/ISO members, participate in a regional wholesale energy market in some fashion. In the Southeast, the Southeast Energy Exchange Market serves as a regional energy trading platform for its members, including the federally owned Tennessee Valley Authority.[179] In the western United States, the majority of utilities participate in the Western Energy Imbalance Market, and several utilities participate in the Extended Day-Ahead Market operated by CAISO (California Independent System Operator) or plan to participate in Markets+, a day-ahead and imbalance market being developed by SPP (Southwest Power Pool). FERC regulates these regional wholesale markets as a new form of wholesale sales in interstate commerce, but this does not fundamentally alter the balance of jurisdictional authority over ratemaking. In state ratemaking proceedings for a vertically integrated utility, all wholesale market purchases and sales show up as a purchased power expense or credit for the customers of the vertically integrated utility.[180]

Regional Transmission Organizations and Independent System Operators

Investor-owned utilities that own transmission can join a Regional Transmission Organization (RTO) or Independent System Operator (ISO).[181] In practice, these are interchangeable terms and can be referred to as RTO/ISOs. RTO/ISOs have their own governance requirements under the relevant FERC orders and provide nondiscriminatory

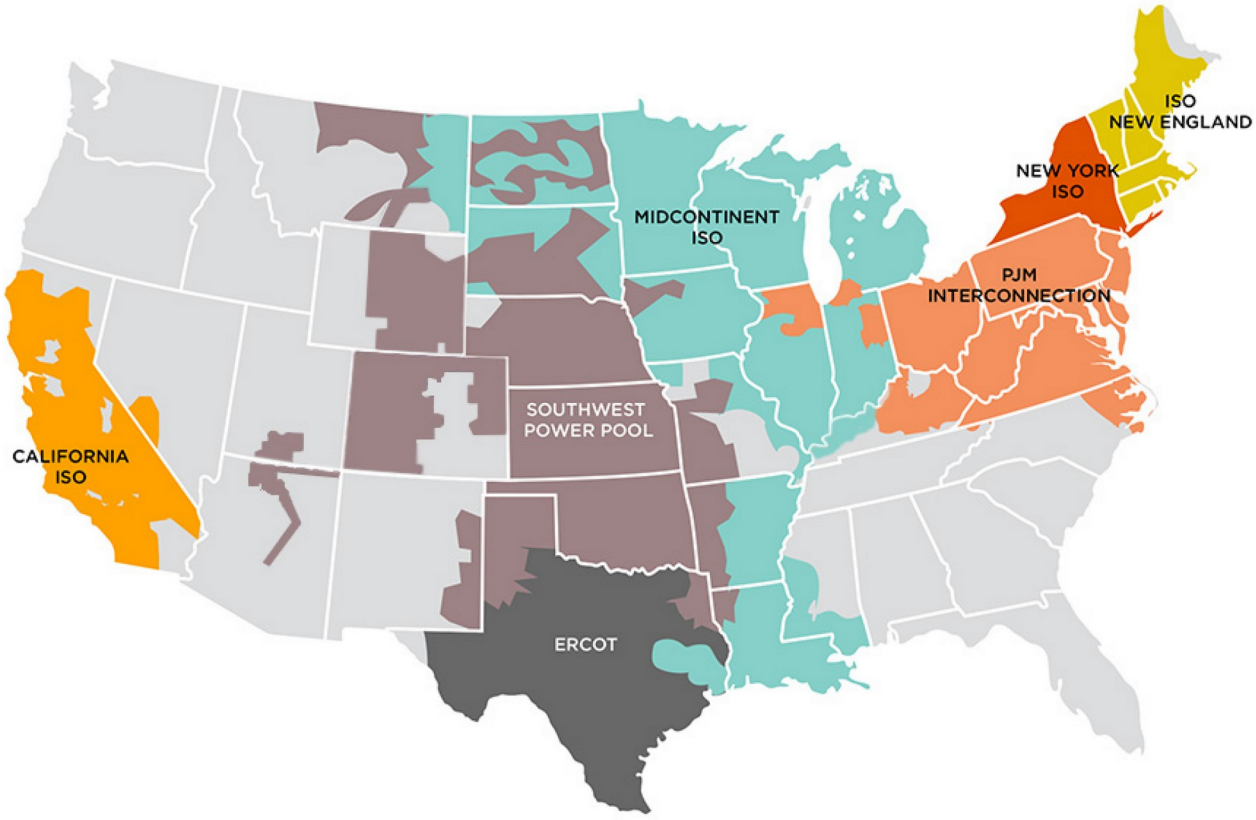
[179] Southeast Energy Exchange Market. (2026, June 24). *Delivering more economic and clean energy to our customers.* https://southeastenergymarket.com/

[180] Because of the filed rate doctrine for FERC-approved rates, there is an important distinction between state-jurisdictional purchased power and sales through FERC-approved regulatory structures. Under FERC-approved regulatory structures, state utility commissions are not allowed to question the prices resulting from the FERC regulatory approach. *Nantahala Power & Light v. Thornburg,* 476 U.S. 953 (1986).

[181] Note that utility participation in a wholesale market run by an RTO/ISO is not the same as utility membership in an RTO/ISO.

transmission network access and different types of wholesale electricity market structures. Figure A-2 below shows the current map of RTO/ISOs. A utility that joins an RTO/ISO hands over operational control of its transmission system to the RTO/ISO but continues to own the assets. RTO/ISOs and regulated transmission owners have transmission tariffs to charge wholesale customers, and FERC oversees those wholesale rates.

Figure A-2. Regional Transmission Organizations / Independent System Operators



Source: Adapted from Sustainable FERC Project. (n.d.). *RTO Backgrounders*. https://sustainableferc.org/rto-backgrounders-2/

FERC oversees six of the RTO/ISOs on this map but has no jurisdiction over ERCOT.[182] Unless mandated by state law, utility membership in an RTO/ISO is voluntary, and these maps have changed over time. Most recently, nine utilities across seven states (Arizona, Colorado, Montana, Nebraska, New Mexico, Utah and Wyoming) joined the SPP RTO's expansion into the western interconnection.[183]

[182] We will follow a convention of including ERCOT as an RTO/ISO. ERCOT refers to itself as an independent system operator: ERCOT (n.d.). *About ERCOT.* https://www.ercot.com/about

[183] Since these new utility members are in the Western Interconnection, this is referred to as SPP RTO West: SPP. (2026). *RTO expansion*. https://www.spp.org/western-services/rto-expansion/

For most RTO/ISO transmission costs, cost allocation is a two-step process:

1. The RTO/ISO establishes wholesale transmission cost allocation and pricing as overseen by FERC.
2. RTOs send bills for wholesale transmission service to local electric distribution companies or load-serving entities.

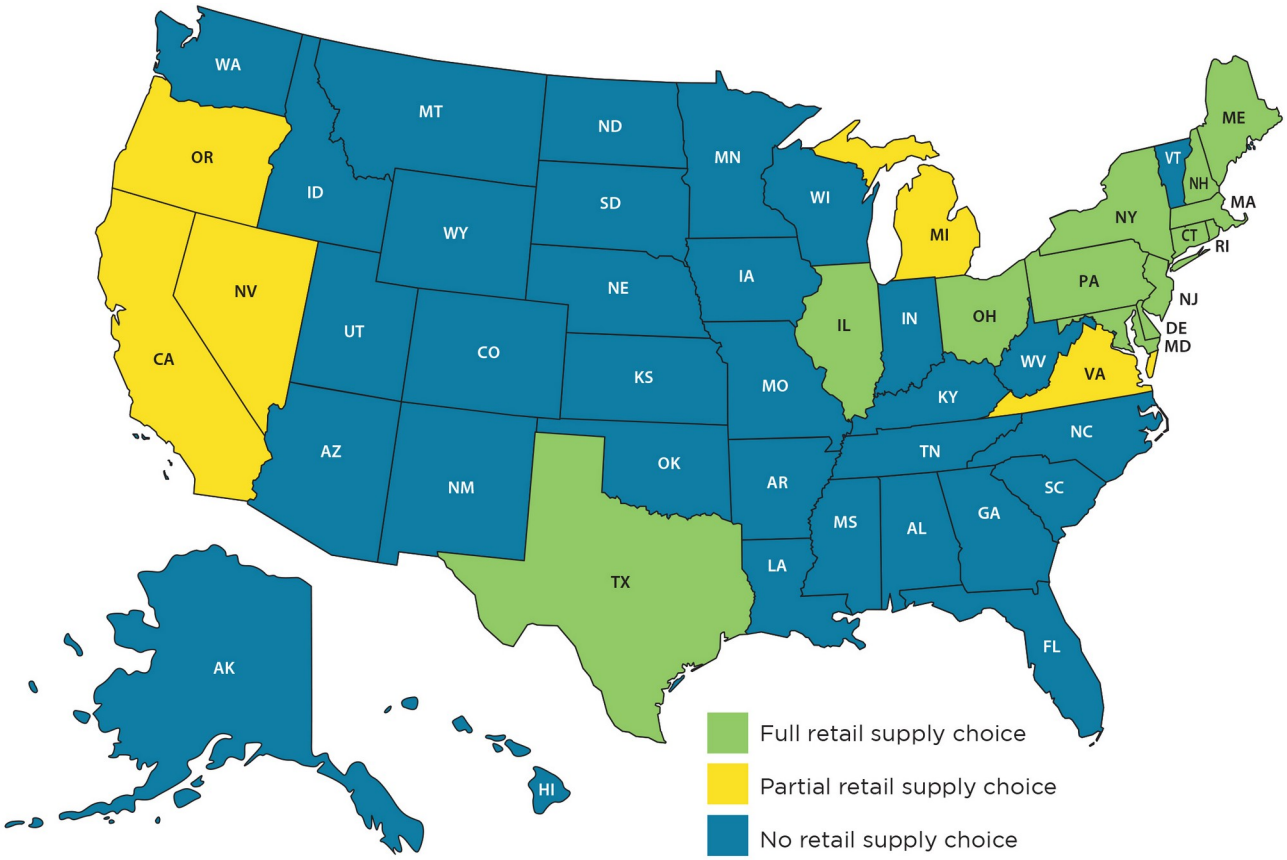
The key substantive distinction here is that regional transmission costs may now be charged in a shared manner across the entire RTO/ISO footprint or different subsets of that footprint. Load-serving entities and electric distribution companies then charge end-use retail customers for these wholesale transmission costs. Transmission owners and the RTO do charge new generation facilities for interconnection costs and could institute similar practices for data center customers connecting to the transmission system.

Full Restructuring and Retail Supply Choice

Working alongside these RTO/ISO reforms, 13 states[184] across four RTO/ISOs (ISO-NE, NYISO, PJM and ERCOT) elected to fully restructure their electric utilities along with their regulatory framework as shown in Figure A-3 below. In 12 states, all major electric utilities joined the relevant RTO/ISO overseen by FERC. There is no FERC oversight of ERCOT, but instead, this is a reallocation of authority across state entities since the Texas Public Utilities Commission oversees ERCOT.

[184] Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Ohio, Illinois and Texas. In the 13 states just mentioned, the ratemaking framework for electric distribution is largely the same as it was before because it remains exclusive state jurisdiction under the Federal Power Act. Other states covered by RTO/ISOs have adopted a hybrid approach discussed in the next section.

Figure A-3. Electric Supply Choice Map



Source: Adapted from Retail Energy Advancement League. (n.d.). *Energy Choice in Your State.* https://www.retailenergychoice.org/energy-choice-in-your-state/

These 13 states passed state laws that required vertically integrated electric utilities to sell their generation assets. Independent power producers in these states are now the primary participants in wholesale energy markets.

In addition to wholesale energy market rules, states define the parameters of retail supply service for end-use customers. In each of these states, retail customers are allowed to choose their own retail generation supply provider and can independently negotiate the price and terms. In most states, a new residential customer is placed on default or basic supply service, where state law and utility commission regulations set procurement rules. In ERCOT, however, there is no default option, and customers are required to choose a competitive supply option when they initiate service.[185] Industrial customers can participate in RTO/ISO markets via a retailer or, in some markets, directly as an end-use customer.

[185] Customers are only placed on "provider of last resort" service if their chosen provider is no longer able to supply service. Public Utility Commission of Texas. (2026). *Electricity options.* https://www.puc.texas.gov/consumer-help/electricity/polr/

Hybrid Regulatory Frameworks

Utilities in CAISO, MISO (Midcontinent Independent System Operator), the SPP, the portion of PJM that is not located in fully restructured jurisdiction and Vermont in ISO-NE operate under hybrid regulatory frameworks. Jurisdictions with hybrid regulatory frameworks cover a spectrum of wholesale energy markets structures, generation ownership, resource adequacy requirements and retail customer supply choice offerings. We can highlight key variations using two state examples: California and Michigan.

- In California, the CAISO wholesale energy market is robust, but resource adequacy is demonstrated by the load-serving entities through administrative processes at the California Public Utilities Commission. The incumbent utilities (PG&E, SCE and SDG&E) in California still own approximately 20% of generation resources, primarily nuclear and hydroelectric facilities. Municipalities are allowed to choose a Community Choice Aggregator (CCA), as a form of retail supply choice.[186] This comes along with an annual non-bypassable fee called the Power Charge Indifference Adjustment.[187] Individual customers within a CCA municipality are allowed to opt out and return to investor-owned electric utility rates.
- In Michigan, the major IOUs own over half of the major in-state generation resources but have joined MISO as an RTO/ISO and participate in wholesale markets for energy and capacity. The Michigan Public Service Commission regulates investor-owned retail utilities using traditional cost-of-service ratemaking but the utilities are required by law to offer customer retail supply choice up to a cap of 10% of utility load.[188]

These examples provide two windows into the variety of different hybrid regulatory frameworks that do not fit the modern definition of a vertically integrated utility nor a fully restructured regulatory framework with unrestricted retail supply choice.

Other Regulatory Paradigms

Co-ops and municipal utilities share much in common.[189] Boards typically govern both. For co-ops, customer-owners elect the board. For municipal utilities, municipal officials sometimes serve as the board or appoint the board, but often the residents of the municipality vote for the board members. Generally, co-op or municipal customers have no retail supply choice, but in the Pacific Northwest, cooperatives have agreed to alternative customer supply procurement structures with technology companies.[190] Co-ops and municipal utilities are typically allowed to own generation resources and transmission

[186] A limited number of large electricity customers that opted into competitive retail supply prior to 2001 have been grandfathered under that framework.

[187] California Public Utilities Commission. (2026). *Community choice aggregation — Consumer information.* https://www.cpuc.ca.gov/consumer-support/consumer-programs-and-services/electrical-energy-and-energy-efficiency/community-choice-aggregation-and-direct-access-/consumer-information-on-ccas---frequently-asked-questions

[188] Michigan Public Service Commission. (n.d.). *Electric customer choice.* https://www.michigan.gov/mpsc/consumer/electricity/choice

[189] Some states have authorized another variation on a self-governed utility called “public utility districts.” https://www.wpuda.org/faqs

[190] Amazon staff. (n.d.). *In eastern Oregon, Amazon is working with a local utility to power AWS data centers with clean energy*. Amazon News. https://www.aboutamazon.com/news/aws/data-center-oregon-renewable-energy

infrastructure but are not obligated to. These entities sometimes directly offer other services to customers, such as broadband internet or water.

The methods by which co-ops and municipal utilities procure their electricity depend greatly on the regulatory framework for the state and region where they are located. For instance, New Hampshire Electric Cooperative is a wholesale transmission customer of ISO-NE and buys power in ISO-NE markets.[191] In contrast, 19 small co-ops in South Carolina banded together to form Central Electric Power Cooperative (Central), a wholesale electric generation and transmission (G&T) cooperative.[192] Central in turn contracts for power with Santee Cooper (a state-owned utility) and Duke Energy (an investor-owned utility).

The Tennessee Valley Authority and four federal power marketing administrations (Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, Southwestern Power Administration) play key generation and transmission roles within their regions. These federal entities have their own governance structures with little direct oversight by FERC. In areas with a federal Power Marketing Administration (PMA), publicly owned utilities and cooperatives purchase "preference supply" of low-cost power from the PMAs.[193]

[191] New Hampshire Electric Co-op. (2025). *The cost of electricity is always our focus*. https://www.nhec.com/the-cost-of-electricity-is-always-our-focus/

[192] Central Electric Power. (n.d.). *Energy portfolio.* https://cepci.org/energy-portfolio/

[193] U.S. Energy Information Administration. (2013, June 12). *Federal power marketing administrations operate across much of the United States.* https://www.eia.gov/todayinenergy/detail.php?id=11651



Regulatory Assistance Project (RAP)®
United States · Belgium · China · Germany · India

1100 13th St NW
Suite 800
Washington, DC 20005, USA

+1 802 223 8199
info@raponline.org
raponline.org

© Regulatory Assistance Project (RAP)®. This work is licensed under a Creative Commons Attribution-NonCommercial License (CC BY-NC 4.0).