Grid Strategies

Federal Transmission Pricing

Options for Ensuring Affordability and Reliability in an Era of High Load Growth

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This presentation summarizes the longer two-volume report on federal transmission pricing. For more details on any of the concepts presented herein, see:

Federal Transmission Pricing Volume 1: The Evolution of Current Policies and Practices

Federal Transmission Pricing Volume 2: Options for Ensuring Affordability and Reliability in an Era of High Load Growth

Download Volumes 1 & 2: https://gridstrategiesllc.com/project/federal-transmission-pricing/

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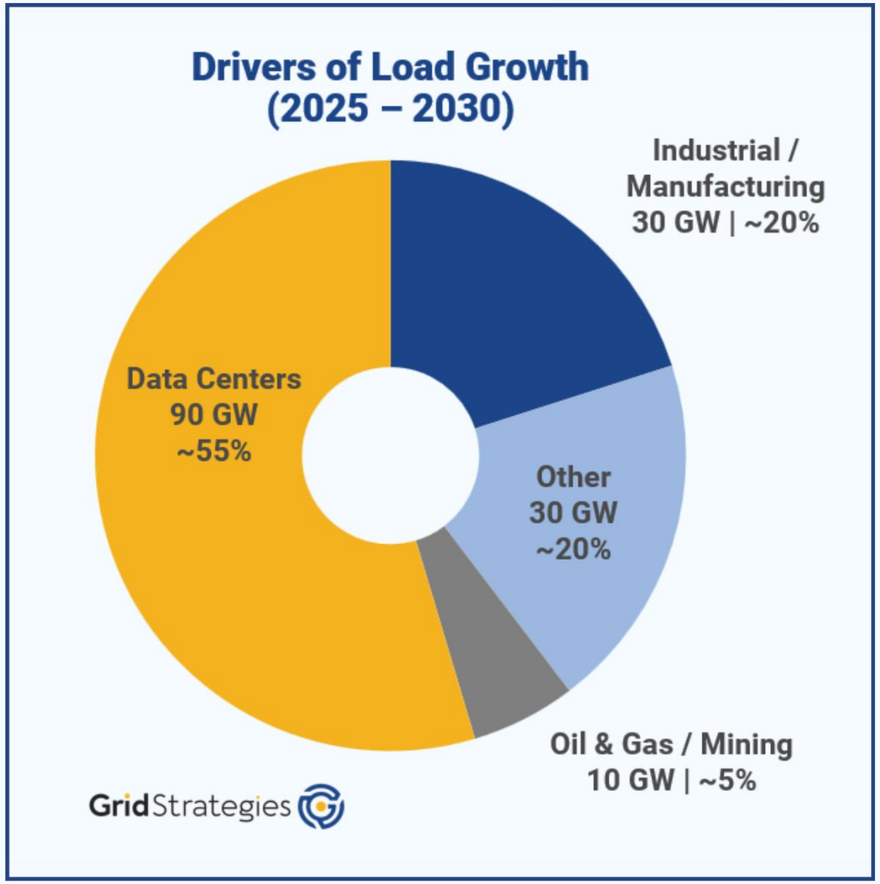
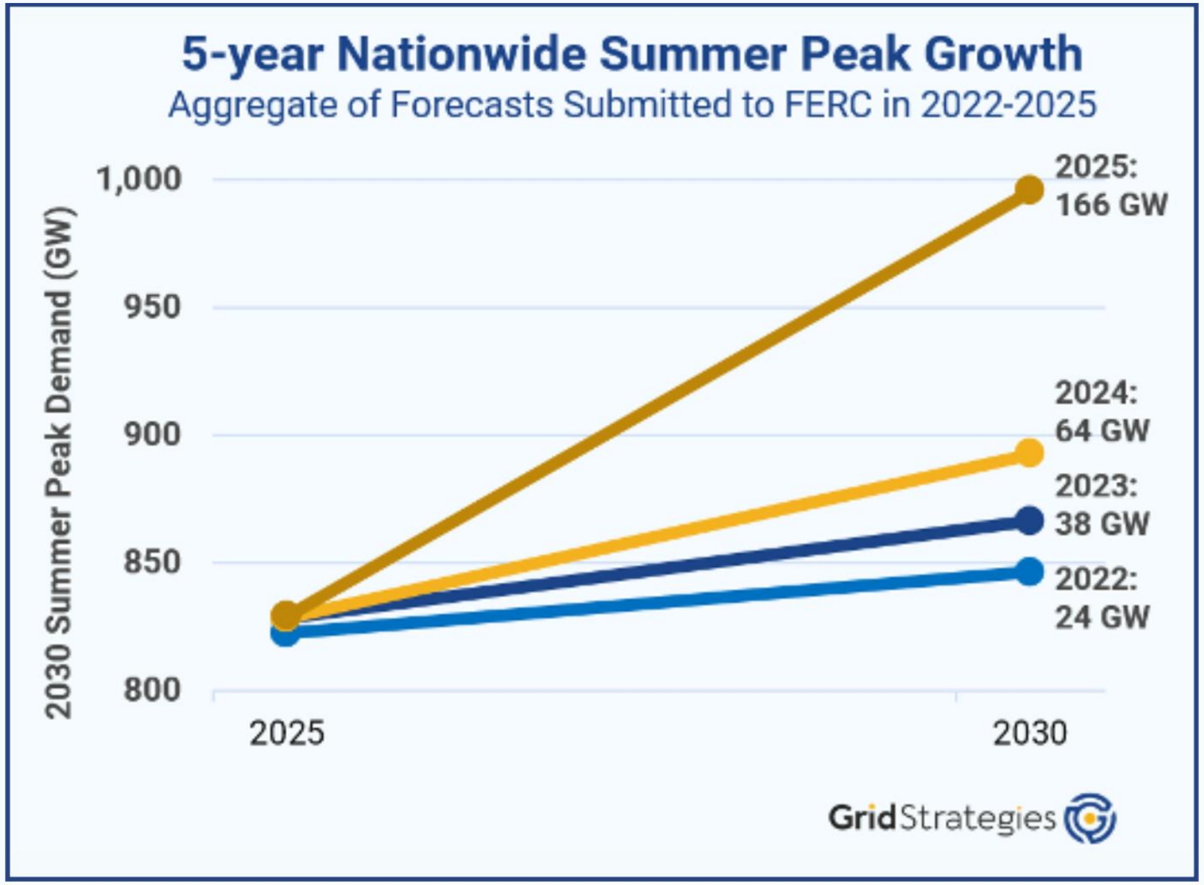
Load growth is accelerating and changing in character





Figures 1 & 2 | Grid Strategies, *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers* (Nov. 2025).

Rising rates and surging large loads: Federal response

Rates are increasing across the country, and drivers vary region to region

- **Utility rate pressure is already high:** Utilities requested nearly $31 billion in rate increases in 2025, more than doubling 2024 requests.
- **Consumers are noticing:** 75% of U.S. adults say home energy costs have increased in recent years.

Rising electricity costs have multiple, often region-specific drivers, including utility investment trends, fuel prices, load growth, wildfires, and extreme weather.

Sources | Pew Research Center, *Rising Home Energy Bills* (May 2026);
PowerLines, *Utility Bills Are Rising: 2025 Review* (Jan. 2026);
LBNL, *Retail Electricity Price Trends and Drivers: 2026 Edition* (Mar. 2026);
White House, *National Policy Framework for Artificial Intelligence* (Mar. 2026);
White House, *Ratepayer Protection Pledge* (Mar. 2026).

There is significant political pressure to respond, with data centers as a focal point

- **Federal policymakers are responding**:
  - March 2026 White House Ratepayer Protection Pledge commits data center companies to pay for new power delivery infrastructure.
  - The White House National Policy Framework for AI calls on Congress to prevent data center growth from raising household bills.
- **Large load customers echo this framing:** Major companies have committed to clearer cost responsibility, infrastructure payments, and “paying their own way” on energy.

Rising rates and surging large loads: State response

State regulators are moving first through large load tariffs

- **Goal**: State tariffs seek to translate uncertain load growth into enforceable customer commitments.
- **Rapid adoption:** There are roughly 77 approved and proposed tariffs and service rules affecting large loads across 36 states and 60 utilities nationally, with more in the works.
- **Customer protection tariff architecture:** Tariffs increasingly pair eligibility thresholds with cost assignment and risk mitigation tools.

State tariffs are the main mechanism for assigning customer-specific commitments and retail cost responsibility, but they depend on FERC-jurisdictional transmission costs being transparent and well-allocated.

Large load tariffs: Common customer protection provisions

Long-term commitments & exit charges

Requires long-term contract, often 10–20 years, with exit charges for early termination

Minimum billing demand

Sets billing floor, often at 80–90% of contract demand, even if actual usage is lower

Security & collateral

Requires collateral or other credit support, such as deposits, letters of credit, or guarantees

Customer-specific facilities

Requires the customer to pay for customer-specific facilities or other non-standard facilities needed to serve the customer

Sources | SEPA, *U.S. Data Center Gold Rush Drives Surge in New Utility Tariffs* (Apr. 2026);
EEI, *Large Load Projects and Tariffs* (May 2026);
E3, *Large Load Tariff Whitepaper* (May 2026).

Robust transmission planning can lower bills

- **The grid needs investment regardless of large loads**: Aging infrastructure and higher equipment costs are already driving capital needs.
- **Planning beats piecemeal buildout**: Proactive, multi-value planning can solve multiple needs at once and avoid reactive, higher-cost local fixes.
- **Large loads also need the grid**: Onsite generation and co-location are often bridge-to-power strategies, not substitutes for transmission; large customers generally seek the reliability, scale, and flexibility of network grid service.

Average annual U.S. household electric bills with and without transmission

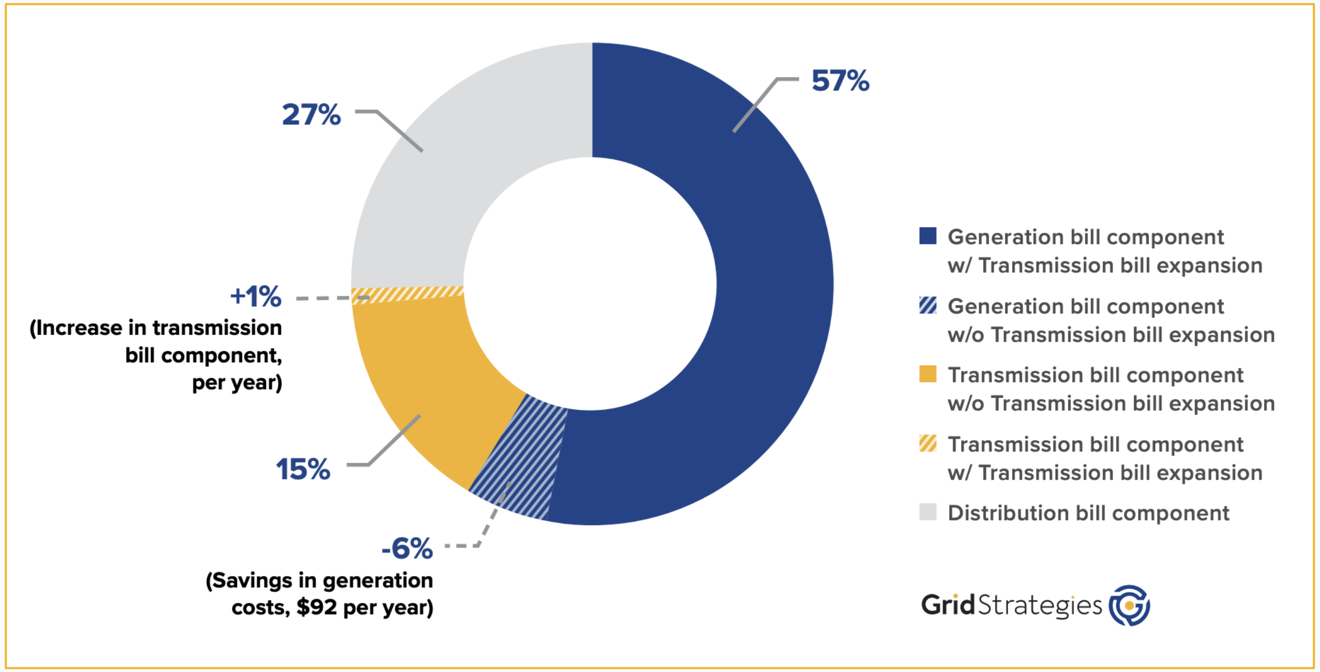


Figure 3 | Grid Strategies, *Large-Scale Transmission Deployment Saves Consumers Money* (June 2025).

Sources | Bank of America Institute, *Power Check* (2025); DOE, *National Transmission Planning Study* (2024); Brattle, *Transmission Landscape and Outlook* (2025); AlphaStruxure, *Before AI, After AI* (2025).

Rate impact depends on system conditions, policy design, and good utility practice

1

System conditions

Is there existing system capacity, or are major generation, transmission, and distribution upgrades needed?

2

Timing of costs and revenues

Do infrastructure costs enter rates before the large loads fully materialize or reach expected demand?

3

Cost allocation and risk mitigation

Are costs assigned appropriately and are stranded cost risks mitigated through commitments, tariff design, and cost allocation?

Federal Transmission Pricing Volume 1

The Evolution of Current Policies and Practices

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Who Regulates What in Transmission Service?

State Regulators (PUCs, PSCs, etc.)	Federal Regulator (FERC)
Rates* for sales to end-use customers (i.e., retail sales)	Rates* for transmission in interstate commerce – rules for planning; approval of cost recovery and cost allocation to wholesale customers (i.e., load serving entities); sets utility's authorized return (cost of capital) on transmission assets, which is included in costs
Allocation of costs among retail customers/ customer classes	Rates for wholesale electricity sales
Generation planning	
Local distribution	
Transmission service in intrastate commerce	
Transmission and generation construction	
Other matters not specifically granted to FERC	

Note: There is no bright line in reality. E.g., FERC has declined to generically assert jurisdiction over transmission in bundled retail sales. FERC also sometimes approves rates for sales to end-use customers.

* "Rates" is shorthand for rates, terms, and conditions. "Rates" is not limited to the ultimate $/kWh rate, but also includes rules governing cost recovery, cost allocation, and rate design at the relevant regulatory level.

TYPICAL UNBUNDLED TRANSMISSION SALE

Open Access Transmission Service at Wholesale

FERC approves transmission costs and allocation	Generally allocated to wholesale customers on demand basis

↓

LSE Takes Transmission Service at Wholesale

LSE pays FERC-approved transmission charges for wholesale purchase	LSE recovers costs from end-use customers via state-approved rate

↓

End-Use Customer Buys from LSE at Retail

State approves LSE rate design, including FERC-approved costs	State allocates FERC-approved costs among customers / customer classes

History of Transmission Pricing Policy

- **Late 1800s** — Bundled retail sales; no regulation
- **Early 1900s** — State regulation of monopoly franchises; state cost-of-service ratemaking
- **1927** — Supreme Court identifies “Attleboro Gap” (no regulation of transmission in interstate commerce)
- **1935** — Public Utility Act grants Federal Power Commission jurisdiction over transmission in interstate commerce
- **1977** — Congress establishes FERC; federal cost-of-service ratemaking
- **1994** — FERC Transmission Pricing Policy Statement; “higher of” pricing allowed; corporate “and” pricing prohibited
- **1996** — FERC Order 888 requires open access and non-discriminatory transmission service; “higher of” continues with introduction of “but for” test for incremental/direct assignment
- **1999** — FERC Order 2000 on RTOs; requires RTOs to eliminate “rate pancaking;” some forms of “and” pricing allowed in RTOs
- **2003** — FERC Order 2003 adopts standard generator interconnection procedures; maintains “higher of” pricing; again allows some form of “and” pricing in RTOs (participant funding)
- **2007** — FERC Order 890 requires open, transparent, and coordinated transmission planning, clear cost allocation, and comparison of rates for “higher of” pricing with robust cost support
- **2011** — FERC Order 1000 requires regional transmission planning and cost allocation; six regional cost allocation principles; emphasis on “beneficiary pays” principle
- **2023** — FERC Order 2023 reforms standard generator interconnection procedures; applies same pricing policy to clusters of generators
- **2024** — FERC Order 1920 on long-term regional transmission planning and cost allocation; moves away from single driver planning and cost allocation; increases role for states

Cost Allocation Methods for Transmission

Cost Allocation Method	Description	Who/Which Transmission Cost
License Plate	Allocates costs to local area in which the transmission is located	• RTOs use for allocating costs of lower-voltage and local transmission to single pricing zone or transmission owner (costs may then be allocated within a single pricing zone using load ratio share where multiple LSEs take service in the zone)
Load Ratio Share (Postage Stamp)	Allocates costs based on amount of load served by wholesale customer in defined area (e.g., region or sub-region) at snapshot in time (e.g., monthly peak) compared to total load served in the area at that time	• Regional transmission • CAISO – regional load ratio share for transmission > 200 kV • ERCOT – regional load ratio share for transmission > 60 kV • ISO-NE – regional load ratio share for reliability + economic-driven regional, and 70% of public policy-driven regional • MISO – regional load ratio share for Multi-Value Projects, with some sub-regional load ratio share for Long Range Transmission Planning portfolios • PJM – regional load ratio share for 50% > $5M and > 500 kV (345 kV double circuit) baseline reliability and economic • SPP – regional load ratio share for 100% > 300 kV, and 33% > 100 kV and < 300 kV; zonal load ratio share 67% > 100 kV and < 300 kV, and 100% < 100 kV
Granular Benefits-Based	Allocates costs by identifying and quantifying specific benefits of transmission and allocating costs based on the quantified benefits to specific beneficiaries, completed through use of complex modeling tools	• Regional transmission • PJM – 100% market efficiency (economic) projects (production costs, congestion relief) • Other RTOs quantify benefits for project evaluation and selection but not for cost allocation, and others have used quantified benefits for a portion of their regional cost allocation in specific circumstances (e.g., NYISO in its Public Policy Transmission Planning Process)
Power Flow-Based (DFAX)	Allocates costs by quantifying distribution factors (the estimated power flows through a transmission facility) to determine who will use and benefit from the transmission and allocate costs to them	• Regional transmission • PJM – solution-based DFAX for 50% > $5M and > 500 kV (345 kV double circuit) baseline reliability, and 100% < $5M and < 500 kV (except stability-driven allocated based on zonal contribution to need)
Voluntary Supplement	Allows states to push a project across the required benefit-cost ratio by agreeing to be allocated any costs above the calculated benefits separate from the standard regional cost allocation method	• Regional transmission • In FERC Order 1920 • ISO-NE – Longer-Term Transmission Planning Process • PJM – State Agreement Approach

Simplified example: Serving a new 1 GW data center

Assumed Facts:

- 1 GW data center requesting service in Zone A
- Zone A contains one transmission owner and one LSE
- Relevant transmission planning region uses load ratio share cost allocation method

5-10 Years Before Data Center Comes Online – New Regional Transmission Planned:

- New regional transmission need identified using inputs that include load forecast with new 1 GW data center in Zone A
- Region selects new transmission project to meet need (quantified reliability and economic benefits exceed costs)
- Region allocates costs of new regional transmission using load ratio share – 70% to Zone A (with new 1 GW data center),* 10% to Zone B, and 20% to Zone C
- State regulated tariff or utility contract determines rate (including transmission), minimum charge, etc., which determined what costs are recovered from customer

1-3 Years Before Data Center Comes Online – New Local Transmission Planned

- Transmission owner in Zone A conducts interconnection study and identifies need for local transmission upgrades to accommodate customer requesting service
- If served by a vertically integrated utility, local upgrade costs recovered from customer through a combination of state-regulated rates and extra facility charges
- If located in an RTO region:
    - Upgrade costs added to transmission owner's embedded cost-based revenue requirement used to establish Zone A transmission service charge allocated to LSEs in the zone on load ratio share basis (100% to the LSE in Zone A)
    - LSE flows FERC-approved transmission costs allocated at wholesale to end-use customers, including new 1 GW data center, according to state-approved rate design (may include separate rate class for large load customers, like the data center)

*Caveat: Initial load ratio share cost allocation does not account for new 1 GW data center because it is not yet part of historic coincident peak-based allocation factor used, but as load shares update over time, the Zone A allocation will increase to account for increased load from the data center.

Federal Transmission Pricing Volume 2:
Options for Ensuring Affordability and Reliability in an Era of High Load Growth

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Five guiding principles for evaluating federal transmission pricing options

1 **Principle 1: Ensure opportunity for appropriate cost recovery**
Transmission owners should have the opportunity to recover prudently incurred costs and a return sufficient to attract future investment.

2 **Principle 2: Safeguard non-discriminatory open access**
Following the Energy Policy Act of 1992, FERC has consistently required open access to the transmission system.

3 **Principle 3: Promote economic efficiency on the electric system**
Economic efficiency should be promoted in transmission expansion, use of existing transmission capacity, and timing/location of new generation and load.

4 **Principle 4: Promote fairness in line with cost causation and beneficiary pays principles**
Those who cause the costs and benefit from the transmission should pay, per longstanding court precedent.

5 **Principle 5: Be administratively feasible, fast, and transparent**
Transmission pricing should be practical and implementable.

Federal Transmission Pricing Options

Some options are exclusive, others can be combined

Timing of Funding

Option 1: LSE Service and Financial Security Commitments

Option 2: LSE Upfront Funding and Reimbursement

Local Transmission Costs

Option 3: Mandatory "Higher of" Pricing

Option 4: New Form of "And" Pricing

Option 5: Large Load-Driven Local Transmission Transparency

Regional Transmission Costs

Option 6: Targeted Cost Allocation of Large Load-Driven Regional Transmission Costs

Option 7: Transparency of Large Load-Driven Regional Transmission Costs

Option 8: Widespread Load Ratio Share Cost Allocation

Option 9: Voluntary Supplement and Expedited Service

Innovative Approaches

Option 10: Planning-Led Zonal Capacity Reservation Model

Option 11: Open Season Model for Large Load Interconnection

Option 12: Consolidated Load and Generation Integration Framework

OPTION 1

LSE service and financial security commitments

- LSEs serving large loads would provide long-term service commitments, collateral, or provide other financial guarantees as a condition of taking FERC-jurisdictional transmission service.
- Tools include long-term service commitments, minimum revenue or minimum payment obligations, security postings, milestone-based development obligations, or other collateral.
- This option primarily addresses stranded cost risk if large loads delay, downsize, or leave the system.

✓ **Supports cost recovery:** Increases certainty that the LSE serving a large load remains responsible for transmission costs and risks over time.

✓ **Improves economic efficiency:** Can improve near-term load forecasting by increasing certainty around committed large loads, supporting better system planning.

✓ **Promotes fairness:** Can reduce the risk that existing customers bear costs if large loads delay, downsize, or leave early.

! **Open access concerns:** Singling out service only to large loads could raise discrimination concerns.

! **Federal-state alignment is essential:** State retail rules would determine whether LSE obligations flow through to the large loads driving the costs.

! **Calibration matters:** Low requirements may not fully protect against stranded costs; excessive requirements could deter viable projects or favor the largest customers.

Administrative complexity of incremental cost pricing

- **Incremental costs are difficult to determine:** Identifying the costs needed to serve a new transmission customer requires a "but for" determination, power flow studies, and robust documentation for filing at FERC.
- **Cost estimates can be unstable:** Assigned costs can vary dramatically based on queue position, nearby requests, withdrawals, and restudies, creating incentives to file multiple or revised requests to improve cost outcomes.
- **Restudies and affected systems can compound delays:** Nearby service requests or cancellations can trigger restudies and nearby affected systems may need to conduct additional transmission impact studies, causing additional delays.
- **Modeling assumptions can drive very different results:** Assumptions may materially change the incremental cost outcome, making it difficult for customers to estimate the cost of interconnecting at a given location and leading to potential disputes.
- **Generator interconnection is a cautionary analogue:** Similar approaches, including participant funding in RTOs, have contributed to years-long delays, repeated restudies, cost uncertainty, and disputes over study assumptions and upgrade cost assignments.

Sources | Grid Strategies & Brattle, *Unlocking America's Energy* (Aug. 2024);
Grid Strategies & Brattle, *Generator Interconnection Scorecard* (Feb. 2024);
Grid Strategies, *Resolving Interconnection Queue Logjams* (Oct. 2021).

OPTION 2

LSE upfront funding and reimbursement

- LSEs would provide upfront payment, on behalf of defined large loads, for specified transmission costs driven by those loads, which could include costs of studies, local transmission, and/or regional transmission.
- Reimbursement would occur through a tariff-defined crediting or repayment mechanism, based on existing FERC-approved generator interconnection reimbursement models.
- This option aims to address front-end risk and timing mismatches while preserving reimbursement.

✓ **Promotes fairness:** Can address front-end timing risk by requiring LSEs to fund specified transmission costs before large loads fully contribute through rates.

✓ **Improves economic efficiency:** Can expose large loads to cost signals around configuration, flexibility, and location, if obligations flow through to retail customers.

✓ **Leverages existing mechanisms:** Adapts FERC-approved generator interconnection funding and reimbursement models rather than starting from scratch, though adaptation to load interconnection would be needed.

! **Open access concerns:** Like Option 1, singling out service to large loads could raise discrimination concerns or disadvantage less-capitalized developers.

! **Complex study requirements:** Depending on how costs are specified, this option could inherit the pitfalls of incremental cost-based pricing.

! **Back-end protection varies:** Faster reimbursement may be less effective at preventing stranded cost risk.

OPTION 3

Mandatory "higher of" pricing

- Transmission providers would be required to charge LSEs serving large loads the "higher of" the embedded cost rate or incremental cost rate for relevant local transmission costs.
- FERC currently allows transmission providers the option of charging the "higher of" rate, but transmission providers infrequently elect incremental cost rates; this option would remove that discretion for LSEs serving large loads.

✓ **Promotes fairness:** Aims to ensure LSEs serving large loads cover the costs of those loads' local transmission impacts, avoiding undue burden on other customers.

✓ **Promotes economic efficiency:** Could send price signals for efficient load configuration and location, if costs flow through to large loads at retail.

✓ **Supports cost recovery:** Requires use of a cost-based rate designed to recover the full cost of new service.

! **Administrative complexity:** Requires determining incremental costs and inherits those difficulties — power flow studies, restudies, and disputes.

! **Open access concerns:** Singling out large load service could raise discrimination concerns and delay access to transmission service.

! **Fairness depends on design:** Pure incremental cost rates can be misaligned with cost causation and beneficiary pays, especially where upgrades provide broader benefits or where large loads do not contribute to embedded system costs.

Marginal cost is not always the same as “fair share”

Pure incremental pricing risks cost shifts in two directions

Pure incremental cost-based pricing may fail to reflect that transmission benefits often extend beyond the customer that triggers the need.

- **Some upgrades benefit more than the triggering customer.** High-voltage transmission can provide both local benefits and regional benefits, so charging 100% of a project to the triggering customer may misalign with beneficiary pays.
- **Incremental-only customers may underpay for the existing grid.** If large loads pay only incremental costs and do not contribute to the costs of the embedded system from which they continue to benefit, costs may shift to other customers.

Figure 4 illustrates how a hypothetical 200 MW load paying only an incremental cost rate may, over time, contribute less than it would under the embedded cost rate.

Cumulative Cost Contributions for Hypothetical Customer for Three Scenarios (2027-2050)

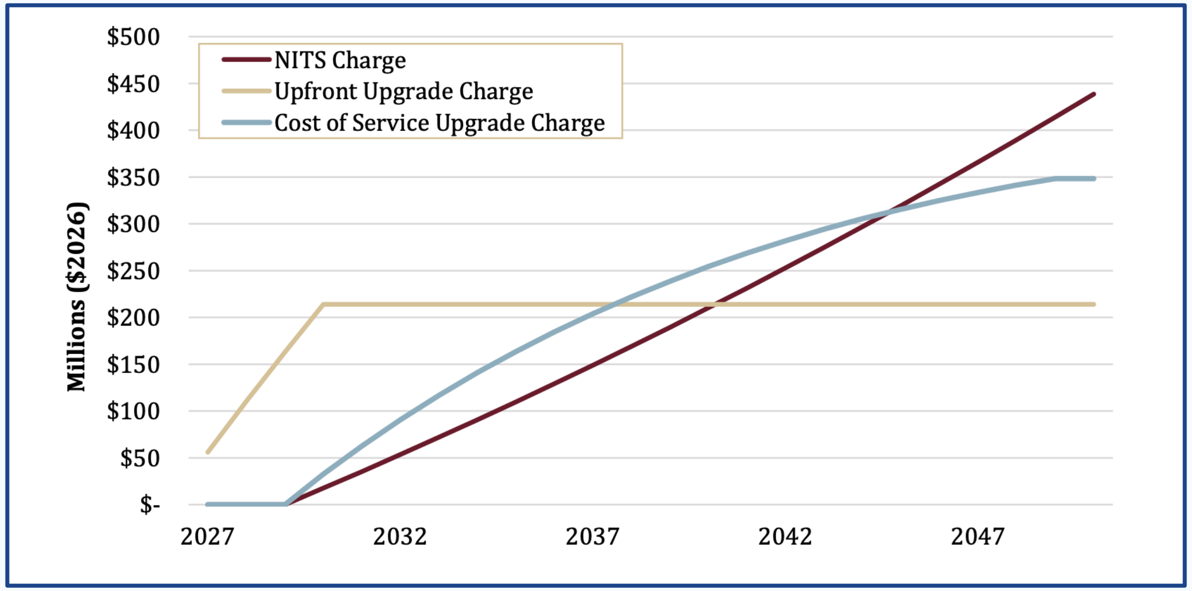

Figure 4 | Concentric Energy Advisors, *The Risks of Cost Shifts in Serving Large Loads* (Mar. 30, 2026).

Sources | *Long Island Power Auth. v. FERC*, 27 F.4th 705, 709 (D.C. Cir. 2022); FERC Order No. 2003 & 2003-A; *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217, PP 205-206, 224-226 (2025); *Commonwealth Edison Co.*, 194 FERC ¶ 61,183 (2026) (Chang, Comm’r, concurring).

OPTION 4

New form of "and" pricing

- Transmission providers would be required to charge LSEs serving large loads both an embedded cost rate and some portion of incremental costs, with those directly assigned costs excluded from the embedded cost rate.
- The incremental cost component could apply only above a specified threshold or could be assigned by percentage or cost category.
- The incremental portion could be paid upfront or over time and would not be reimbursed.

✓ **Promotes fairness:** Could reduce underpayment risk by requiring large loads to contribute to both marginal costs and the existing transmission system.

✓ **Promotes economic efficiency:** Could send price signals for efficient load configuration and location, if costs flow through to large loads at retail.

! **Open access concerns:** FERC has generally prohibited "and" pricing outside RTOs; singling out service to large loads would need justification.

! **Over-recovery risk:** Charging both incremental and embedded costs requires careful design to avoid double-counting.

! **Administrative complexity:** Incremental pricing challenges remain; could be reduced by narrowly defining the affected large loads.

OPTION 5

Large load-driven local transmission transparency

- Transmission providers would identify the costs of local transmission driven by large loads.
- Costs could be reported project-by-project or grouped under a large load-related tag or category.
- The aim of this option is to improve transparency without changing federal cost allocation or cost recovery mechanisms.

✓ **Promotes fairness:** Enables states to allocate costs more accurately to cost causers at the retail level.

✓ **Supports economic efficiency:** Better cost visibility can inform more efficient planning and reduce reliance on piecemeal local upgrades.

✓ **Maintains cost recovery:** Avoids any threat to fair cost recovery opportunity by maintaining status quo cost recovery.

! **Information is not action:** Transparency alone does not ensure that costs flow through to large loads at retail, prevent unfair cost shifts, or produce more efficient outcomes.

! **Data alignment challenges:** For project-specific reporting to be useful to state regulators, transmission owner reporting must align with RTO records so that projects are identifiable.

OPTION 6

Targeted cost allocation of large load-driven regional transmission costs

- Transmission planning regions would allocate large load-driven regional transmission costs to LSEs serving those loads.
- Identification of costs would be done via with/without analysis comparing regional needs with and without the defined large loads, or proxy methods, such as SPP-style exploratory transmission costs.

✓ **Targets interstate cost shift concerns:** Could respond to concerns that regional transmission costs are being driven by large loads in one state but allocated more broadly across the region, which state-level regulation cannot address alone.

✓ **Promotes fairness:** Allocates large load-driven regional costs to LSEs serving those loads, though retail pass-through still depends on state rules.

✓ **Maintains cost recovery:** Costs would still be fully allocated among LSEs.

! **Load materialization risk:** If large loads fail to materialize, are delayed, or exit early, LSEs assigned large load-driven regional costs may be left with stranded costs unless the framework includes a reallocation mechanism.

! **Administratively burdensome:** With/without analyses or proxy methods could be time-consuming, contentious, and difficult to administer.

! **May undermine multi-value planning:** Separating large load-driven costs could create pressure for narrower, short-sighted solutions.

OPTION 7

Transparency of large load-driven regional transmission costs

- Transmission planning regions would identify the costs of regional transmission projects driven by large loads, as in Option 6.
- Unlike Option 6, existing regional cost allocation methods would still apply; the identified costs would be informational only.
- As with Option 5, the aim of this option is to improve transparency without changing federal cost allocation or cost recovery mechanisms.

✓ **Promotes fairness:** Helps states identify regional transmission costs associated with large loads, allowing for reflection in retail ratemaking (e.g., inclusion in large load tariffs or contracts).

✓ **Less disruptive than reallocation:** Improves information availability without disrupting opportunities for cost recovery or upsetting approved regional cost allocation methods.

✓ **Supports economic efficiency:** Gives states and stakeholders more visibility into regional cost drivers, which can inform future policy and support greater buy-in.

! **Information is not action:** Transparency alone does not ensure that large load-driven regional costs are assigned to large loads or avoid unfair cost shifts.

! **State tools may be limited:** Retail ratemaking may not fully address regional cost allocation issues, especially those that cross state boundaries.

! **Administratively burdensome:** With/without analyses or proxy methods could be time-consuming, contentious, and difficult to administer.

OPTION 8

Widespread load ratio share cost allocation

- Regional transmission costs would be allocated using load ratio share, a widely-used cost allocation methodology that assigns costs based on each LSE's or zone's share of load in the region.
- Load shares would be updated on a regular, administrable basis so regional cost allocation reflects changing demand.
- A key design choice is the allocation factor, i.e., the input used to calculate load shares, as illustrated by sub-options 8A through 8D.

✓ **Supports multi-value planning:** Preserves multi-value regional transmission planning by avoiding project-by-project separation of large load-driven costs.

✓ **Adapts to changing load patterns:** Regular load share updates help costs follow load as it grows, though not necessarily based on each large load's specific cost impacts.

✓ **Avoids discrimination & jurisdictional concerns:** Applies broadly to LSEs without singling out particular customers.

✓ **Administratively practical:** Builds on a regional cost allocation method already commonly used.

! **Disputes may create implementation delays:** Changing methodology could substantially shift costs between states, zones, and LSEs, leading to contentious implementation.

! **Allocator choice:** Different allocation factors create different incentives and fairness outcomes.

! **Less targeted to cost causation:** Load patterns alone may not fully capture cost causation or beneficiary pays for all regional benefits and may fail to reflect the different spread of benefits across voltages.

SUB-OPTIONS 8A & 8B

Peak-based allocation factors: historic vs. forecasted coincident peak

8A Historic coincident peak

- Allocates costs based on each LSE's historic contribution to CP.
- CP-based allocation reflects that transmission is often planned to serve peak demand.
- Pure CP-based allocation may not fully reflect the benefits received by high load factor loads, which rely on the transmission system more continuously than other loads.

8B Forecasted coincident peak

- Uses forecasted peak demand, in whole or in part, rather than relying exclusively on historical peak demand.
- May better align cost allocation where load growth is driving significant transmission investment.
- Tying cost allocation to forecasts could discourage over-forecasting, but may also incentivize under-forecasting, under-planning, and greater reliance on piecemeal local upgrades.

Coincident peak (CP): Demand at the time the broader system reaches peak demand

- **1CP:** Each entity's share of demand during one annual CP
- **4CP:** Average share across four CPs, commonly seasonal/summer
- **12CP:** Average share across 12 monthly CPs

CP-based Allocation:

Incentivizing flexibility or over-rewarding strategic curtailment?

- Can incentivize load-side flexibility by rewarding peak avoidance behavior.
- May over-reward limited curtailment during predictable peak intervals, especially where sophisticated large loads can avoid a small number of measured peaks.
- 1CP, 4CP, and 12CP differ in how strongly they reward peak shaving and capture broader system use—12CP may be less susceptible to avoidance and better reflect system usage.

SUB-OPTIONS 8C & 8D

Usage- and growth-based allocation factors

8C Energy usage-based

Load shares are based on each LSE's share of total energy usage across the region.

- Could be hybridized with peak-based factors.
- May better reflect the intensive grid usage of high load factor loads.
- May more accurately capture grid benefits received by flexible loads or loads with on-site generation than CP-based methods but may fail to incentivize load-side flexibility.
- May be misaligned with cost causation where transmission is designed to meet peak demand.
- Forecasted variants would depend on uncertain load factor and load shape assumptions.

8D Incremental load growth-based

Load shares are based on projected load growth between a future planning year and the current year; a zone with high projected demand pays more than one with flat growth.

- Could be hybridized with other approaches.
- Could be applied based on CP or energy usage.
- May better align cost allocation where load growth is driving significant transmission investment.
- Could produce results directionally similar to targeted large load regional allocation, but without the burden of a with/without analysis.
- Focusing too narrowly on growth could undervalue broader regional transmission benefits.
- Raises the same forecast risk concerns as 8B (forecasted CP).

Treatment of co-located load in cost allocation factors

- Methods that rely on energy usage or coincident peak-based allocation factors must grapple with how to treat load with on-site generation (co-located load), especially when co-located large loads materially affect an LSE's load share for local or regional cost allocation.
- A load partially served by onsite generation has lower net withdrawals, but still relies on the broader system for reliability, backup, balancing, and other grid services.
- The choice of load measure—gross load, net withdrawals, contract demand, or another proxy—materially affects the load-based cost allocation factor.
- Gross load (total load, without discounting for on-site generation) could overstate co-located load's cost responsibility; net load (load not served by on-site generation) could understate continued reliance on the transmission system.
- PJM co-location: Rather than relying on gross or net load alone, FERC has directed PJM to develop Firm Contract Demand and Non-Firm Contract Demand transmission service options. Under this approach, LSEs, on behalf of co-located loads, can reserve, and be charged for, a specified level of transmission service.

Source | *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2025).

OPTION 9

Voluntary supplement and expedited service

- LSEs, on behalf of large loads, could voluntarily pay to offset costs of regional transmission projects that fail the benefit-cost threshold but provide value to those customers, in exchange for service benefits.
- This approach is modeled on the voluntary supplement option Order 1920 provides for states.

✓ **Supports cost recovery & preserves status quo allocation:** Voluntary contributions add to cost recovery without disrupting existing allocation.

✓ **Supports economic efficiency:** Willing capital could help move efficient regional projects forward where the alternative may be slower, more fragmented local upgrades.

✓ **Administratively practical:** Relies on existing benefit-cost analysis practices.

! **Voluntary may not be truly voluntary:** If timely grid access is otherwise unavailable, supplements could become the only viable path.

! **Capitalization concerns:** Could advantage the best-capitalized customers and create barriers for smaller or less established large load developers.

! **Implementation complexity:** Regions would need standard agreements, funding assurances, and clear definitions of associated service benefits.

OPTION 10

Planning-led zonal capacity reservation model

- Transmission providers would proactively identify zones where existing capacity or planned upgrades could support additional large load interconnection.
- Transmission providers would specify the incremental withdrawal capability available in each zone and the terms for accessing it.
- Qualifying large loads would receive standardized service rights by meeting readiness requirements and making binding financial commitments.

✓ **Improves economic efficiency:** Proactive multi-customer planning improves siting, timing, and economies of scale while exposing customers to pricing signals.

✓ **Supports cost recovery & prevents cost shift:** Binding financial commitments derisk the zonal upgrade portfolio.

✓ **Supports speed and transparency:** Gives large loads clearer information about where service is available and on what terms.

! **Major administrative lift:** Would require significant changes to transmission planning and capacity allocation practices, especially in regions without zonal planning constructs.

! **Open access concerns:** Readiness and financial requirements could become barriers for smaller or less-established developers, unless well calibrated.

! **Planning judgment risk:** Depends on credible transmission provider judgments about where load will materialize and how much capacity to reserve.

OPTION 11

Open season model for large load interconnection

- Transmission providers would identify available capacity or upgrade portfolios capable of supporting additional large load interconnection.
- Access would be allocated through a structured open season or auction-like process using financially binding bids submitted by large loads or by LSEs acting on their behalf.
- Winning bidders would receive defined interconnection and withdrawal rights that may be transferable subject to anti-hoarding rules.

✓ **Supports cost recovery:** Investment moves forward if sufficient revenue is raised by the bids, backed by binding financial commitments.

✓ **Efficiently allocates scarce capacity:** Uses bid-based allocation and transparent criteria to distinguish among projects and signal the relative value of speed, flexibility, and location.

✓ **Reduces discretionary selection:** Uses transparent bid criteria rather than queue position or planner discretion.

! **Novel design challenge:** With no direct precedent in transmission load interconnection, regions would need to design new products and processes, including clearly defined interconnection and withdrawal rights.

! **Anti-hoarding rules required:** Transferable rights need guardrails to prevent gaming.

! **Open access concerns:** Bid-based allocation could advantage the best-capitalized customers.

OPTION 12

Consolidated load and generation integration framework

- Transmission providers would adopt a more integrated planning framework for new large loads, modeled in part on SPP's Consolidated Planning Process (CPP).
- Large load service needs would be evaluated alongside generator interconnection and broader transmission expansion needs.
- The framework could include coordinated assessments, earlier identification of upgrades with multiple drivers, standardized $/MW contributions, milestones, and financial commitments.

✓ **Supports speed to power:** Could reduce duplicative or serial study processes.

✓ **Improves economic efficiency:** Coordinated planning across drivers (reliability, economics, generator interconnection, large load) encourages a more efficient transmission buildout.

✓ **Improves standardization:** Could provide a more transparent and standardized framework for large load treatment than utility-by-utility or state-by-state bespoke arrangements.

! **Implementation novelty:** Extending CPP-like concepts to address large loads would require significant tariff development.

! **Materialization risk:** Without meaningful milestones, security, or crediting mechanisms, proactive planning could expose other customers if projected large loads fail to materialize.

! **Governance complexity:** Requires closer coordination among RTOs, TOs, LSEs, large loads, and states.

Conclusion

- In many places, existing mechanisms may already be reasonably well-suited, so it is crucial to **define the problem before changing the framework.**
- Different transmission costs are allocated and recovered in different ways—**adjusting one piece may not deliver the intended result** unless the pieces are considered together.
- **Timing matters**—policymakers must address front-end risk before large loads fully materialize and back-end risk if customers downsize or leave.
- The federal task may not be to upend the existing framework but to **ensure FERC-jurisdictional rules work effectively alongside state retail mechanisms; greater federal-state coordination is likely necessary.**
- Leave room for **innovation**—**bottom-up proposals** from states, utilities, RTOs, and large load customers may offer the most durable solutions.

Glossary of Acronyms

- CAISO – California Independent System Operator
- CP – Coincident Peak
- CPP – Consolidated Planning Process
- DOE – U.S. Department of Energy
- ERCOT – Electric Reliability Council of Texas
- FERC – Federal Energy Regulatory Commission
- ISO – Independent System Operator
- ISO-NE – ISO New England
- LSE – Load Serving Entity
- MISO – Midcontinent Independent System Operator
- PJM – PJM Interconnection
- PSC – Public Service Commission
- PUC – Public Utility Commission
- RTO – Regional Transmission Organization
- SPP – Southwest Power Pool
- TO – Transmission Owner

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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in state regulation, transmission planning, and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.