트레이드 렌즈
TRADE LENS

투자에 초점을 맞추다.

LENS INSIGHT / No.12

U.S. large loads · Transmission and distribution · Contract risk

The Bill for AI Data Center Regulation

Who Pays for Grid Expansion?

Tracing the obligations of developers, utilities and existing customers

Minimum bills

Obligations when demand falls short

Long contracts

Aligning assets and customer commitments

Credit support

Collecting after cancellation or default

Grid costs do not disappear.

Contracts change who bears costs and failure risk.

Separating upfront funding, tariff recovery, underutilization and project cancellation.

Analysis date 2026.11.07

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Industry structure · Cost allocation · Contract economics

01 / RESEARCH VIEW

Start with who bears the cost of failure

TradeLens view | Enforceable contracts and utilization matter more than reserved megawatts.

Core conclusion

U.S. large-load reforms are not a way to eliminate grid investment. They increasingly tie long-term payment and cancellation obligations to the customers driving that investment. The relative advantage shifts toward sponsors able to demonstrate credit strength, real demand and credible phased deployment—not simply the largest connection request. [1] [6] [8]

Analytical lens	The economic distinction
Who funds first?	A utility can own and fund infrastructure while recovering its cost from a customer through tariffs and guarantees.
Who ultimately pays?	Allocation, billing and collection must be followed through to the treatment of any remaining balance.
Who bears failure risk?	Late energization, low utilization, cancellation and default trigger different obligations. A face-value promise is not full protection.

Higher commitments can discourage speculative reservations and increase funding needs for developments without secured tenants. Yet collectible contracts also reduce utilities' recovery uncertainty and can enable necessary investment. Stronger safeguards and continued construction are not inherently contradictory.

Base path

Selective expansion backed by credit and committed demand

Upside evidence

Flexibility and existing-grid use demonstrably reduce new costs

Downside evidence

Defaults and exits still shift costs to existing customers

Scope: U.S. federal, regional-market and state arrangements. There is no assumption of one national data-center tariff. Implications for Korean suppliers are conditional analysis.

02 / THE FIVE BILLS

“Power cost” contains several different bills

Separate network investment, generation adequacy and energy consumed before allocating costs.

Cost layer	What is being paid for?	Allocation question
Dedicated connection	Lines and substations connecting a particular site	Dedicated assets or shared use?
Shared transmission	Regional power transfers and system reliability	Cost causation, joint benefits and approved rates
Distribution / delivery	Local networks and end-use delivery	Service class, capacity and state tariffs
Generation capacity	Ability to supply electricity at peak times	Capacity markets, long-term contracts and load growth
Energy procurement	Electricity corresponding to consumed MWh	Wholesale prices, retail contracts and hedges

TradeLens classification based on the regulatory framework. Retail bills do not necessarily display identical accounting labels. [1] [2] [9]

Buying generation capability is not building a transmission line

PJM’s reliability backstop addresses a generation-capacity shortfall. Adding that procurement to network construction costs, or comparing its MW directly with an energy price per MWh, mixes different measures. A network can lack available generation; generation can lack a deliverable connection. [9]

Changing the energy supplier does not eliminate procurement risk

PUCO requires 180-day notice when large data centers return to default supply, with dedicated procurement costs assigned to those customers. Appropriate network allocation alone cannot protect others if the resulting wholesale energy risk is pooled with ordinary customers. [15]

> **Decision rule**
>
> **“The data center pays” is meaningful only when the cost category is specified. Paying for dedicated facilities does not automatically settle shared-network, capacity or energy exposure.**

03 / REGULATORY STATUS

Distinguish effective rules from pending proposals

As of 7 November 2026. Board decisions, federal approval and implementation are separate stages.

Framework	Current stage	What can be assumed?
FERC regional cases [1]	18 Jun preliminary findings; responses due 16 / 20 Nov	Direction of reform, not a final national tariff
AEP Ohio DCT [4] [6]	Effective 23 Jul 2025; contracts and studies operating	Obligations for covered customers in its territory
Virginia GS-5 [7]	Final order approved; starts 1 Jan 2027	Approved future terms, with legacy exceptions
SPP CHILLS [10]	5 Jun 2026 acceptance order; July implementation	Limits of conditional non-firm service
CAISO Large Loads [3]	28 Oct board approval; 16 Nov federal filing scheduled	Not yet federal approval or full implementation
PJM revised RBP [9]	29 Oct filing; launch targeted for 1 Mar 2027	Proposed allocation and timetable, subject to resolution

A FERC show-cause order asks an operator to justify its tariff or propose changes. Responses are due on 16 November for five regions and 20 November for SPP; these are not dates when a new national electricity price takes effect. [1]

The same decision affects new and existing projects differently

Approved future terms can alter a new project's contract choices before energization. They need not immediately change legacy bills. Contract dates, service dates, expansions, exemptions and transition provisions determine when policy becomes a cash obligation.

> **Current assessment**
>
> **The direction is stronger alignment between cost causation and payment. Scope, amount and duration remain regional and state-specific. Model effective obligations, but do not book a pending proposal as an unconditional cash expense.**

04 / FROM RULES TO CASH

Allocation, billing and collection are three gates

Trace the obligation from federal transmission arrangements to the end customer's retail bill.

Federal / regional
Transmission and wholesale obligations

›

Utilities / LSEs
Allocated costs and recovery contracts

›

State / retail
Customer-class bills and security

An LSE purchases or manages supply for end users. This simplified diagram does not imply that every utility has the same business model. [1] [9]

Gate	Failure mode	Protection mechanism
1. Allocate causally	Dedicated costs fall on others, or all shared benefits are charged to the newcomer	Disclose asset purpose, benefits and incremental cost
2. Bill consistently	Customer contributions are collected again through network rates	Credit recoveries against revenue requirements
3. Collect cash	A long-term promise turns into an unpaid claim after customer failure	Collateral, guarantees, exit duties and reassignment

The NYISO show-cause order considers cost-recovery agreements and credit support, including how customer payments offset transmission revenue requirements and interact with suitable retail security. These are preliminary remedies, not a uniform final rule across all regions. [2]

Clear recovery can also enable necessary investment

Capital expenditure creates an asset; allowed revenue and customer payments convert it back into cash. Uncertain recovery can delay investment even with an unchanged demand forecast. Transparent allocation and enforceable contracts therefore support both consumer protection and project execution.

> **TradeLens interpretation**
>
> **More collateral alone does not make a tariff fair. Legitimately allocated costs must be billed without duplication and remain collectible. All three gates matter to customer protection and project economics.**

05 / OHIO CONTRACT DESIGN

Ohio puts a contractual price on demand shortfalls

The key is how long—and how little a facility can use—while still owing a minimum payment.

Stage	Published mechanism	Risk transferred
Before service	LOA responsibility for construction cost on cancellation or delay exceeding 12 months [4]	Dedicated-investment exposure tied to developer
Load ramp	Up to four years; initial term is ramp plus eight years [4]	Long-lived reservation of unused capacity becomes costly
Operation	Billing combines actual peak, historical peak and contractual minimum demand [5]	Lower use does not fully reduce charges
Credit support	Customers not qualifying for exemption face security equal to 50% of minimum charges over the term [5]	Guarantees or collateral backstop payment exposure
Early exit	Eligibility includes five years after ramp; fee linked to 36 months of minimum charges [5]	Departure is tied to remaining contractual commitments

Construction responsibility, minimum operating bills and exit fees address different events. The applicable obligation changes as facilities are completed and service begins. Adding all three as simultaneously certain expenses can overstate project cost.

Credit quality affects more than the electricity rate

Collateral is not necessarily an equal-sized income-statement expense. A cash deposit has a funding opportunity cost; a letter of credit uses bank capacity and fees; a parent guarantee uses sponsor credit. Identical facilities can therefore face different financing burdens.

> **Interpretation boundary**
>
> **Security is a means of collecting an allocated obligation, not automatically another power cost on top of it. Exemptions, reassignment and actual exit liability depend on contract and credit conditions.**

06 / MINIMUM DEMAND

A single “85%” shortcut misprices the contract

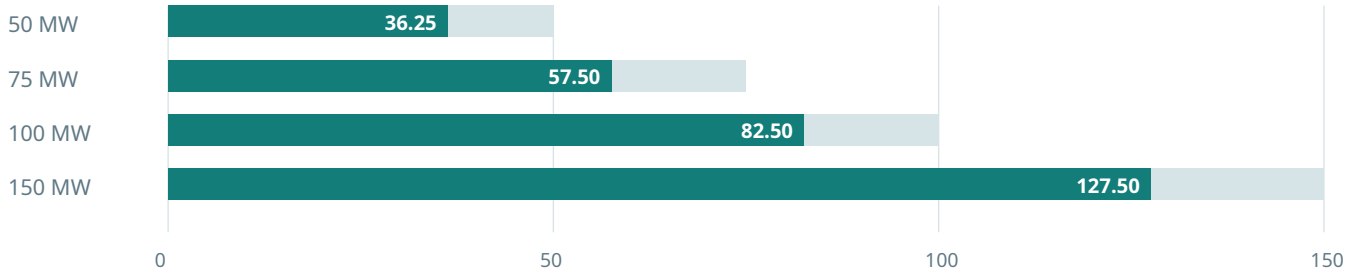
AEP Ohio new-load formula after ramp completion; capacity is expressed in MW.

For 25 < C ≤ 75: m(C) = 15 + 0.85 × (C − 25)
For C > 75: m(C) = min[57.5 + (C − 75), 0.85 × C]

C is total contract capacity; m(C) is its formula-based floor. Actual monthly peak and 85% of the highest prior billing demand in the preceding 11 months can produce a higher bill. [4] [5]

Contract capacity and minimum demand (MW)

Grey: contract / Teal: formula floor



Contract C	Formula floor m(C)	Share of contract
50 MW	36.25 MW	72.5%
75 MW	57.50 MW	76.7%
100 MW	82.50 MW	82.5%
150 MW	127.50 MW	85.0%

For a 100 MW contract with an actual monthly peak of 60 MW, the floor is 82.5 MW if the historical ratchet is no higher. This is neither 82.5 MWh consumed nor a statement that every bill component equals 82.5% of its maximum.

Economic meaning

Starting smaller changes both actual consumption and the contractual floor. A historical peak can also keep charges elevated after load falls. Contract size, phased ramp and peak history must be planned together.

07 / VIRGINIA COMPARISON

Virginia’s 85% has a different denominator

Compare approved GS-5 terms with Ohio DCT without treating either as a national tariff.

Dimension	AEP Ohio DCT	Dominion Virginia GS-5
Typical scope	New or expanded data-center load above 25 MW	At least 25 MW and 75% load factor, among other criteria
Minimum mechanism	Size-dependent demand floor and historical peak	85% transmission; 85% distribution; 60% generation demand floors
Term	Up to four years of ramp plus eight years	14 years for covered new contracts, including up to four ramp years
Timing / exceptions	Effective; existing load distinguished	Starts 1 Jan 2027; legacy customer and contract exceptions
Key question	Which demand calculation is binding?	Which cost component carries the minimum?

Summary only, not a complete site quotation. Ohio guide and tariff [4] [5]; Virginia final order, pp. 23–26 [7].

Do not automatically include capacity costs in the 60% floor

The Virginia order excludes PJM capacity expenses from the minimum generation charge. Averaging 85% and 60% to infer an all-in bill obligation is incorrect. Underlying rates, cost allocation, consumption and exceptions must be treated separately. [7]

A separate customer class does not finish the allocation exercise

SCC also requires alternative cost-allocation proposals. A separate class can still be poorly designed if shared benefits, peak contributions and incremental costs are allocated incorrectly. [8]

> **TradeLens view**
>
> **Long commitments support recovery, but power obligations can outlast technology cycles or tenant contracts. The central development risk is a mismatch between tenant-backed cash flows and the utility commitment.**

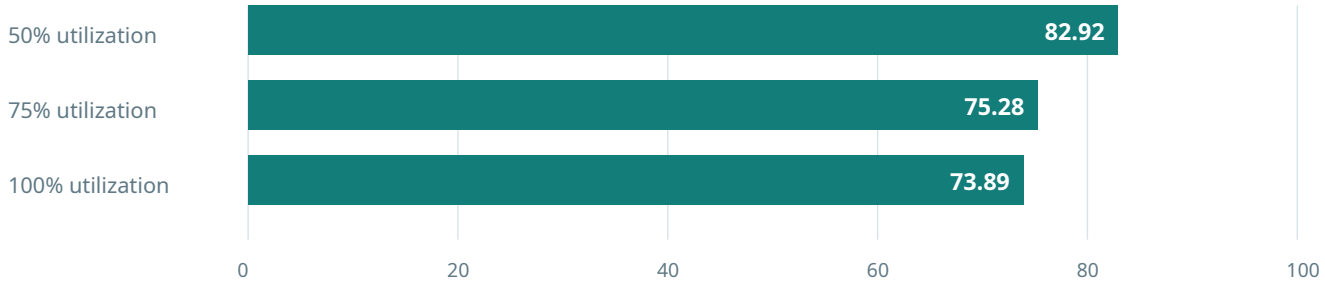
08 / UTILIZATION ECONOMICS

Lower utilization raises cost per MWh consumed

Illustration only | Isolating the floor's economics, not quoting an actual AEP electricity bill.

Assume a 100 MW contract, completed ramp and no higher historical ratchet: m(C)=82.5 MW. Load is constant over a 720-hour month. Assumed rates are $10/kW-month for one demand component and $60/MWh for energy. Other charges, taxes and financing are excluded. [4] [5]

Illustrative unit cost (USD/MWh)



Actual / contract	Billed demand	Monthly cost	Cost per MWh
50%	82.5 MW	$2.985m	$82.92
75%	82.5 MW	$4.065m	$75.28
100%	100.0 MW	$5.320m	$73.89

Monthly cost = 10 × 1,000 × max(actual MW, 82.5)
+ 60 × actual MW × 720

At 50% utilization, the total payment falls but the unit cost is 12.2% above the fully utilized case. Consumption halves while the demand-charge obligation does not. Variable real-world load also requires peak demand, load factor and time-dependent pricing.

What to underwrite

When power commitments run ahead of GPU deployment, charges for unused capacity may arrive first. Secured tenants, staged delivery and aligned billing-start provisions become sources of cost competitiveness.

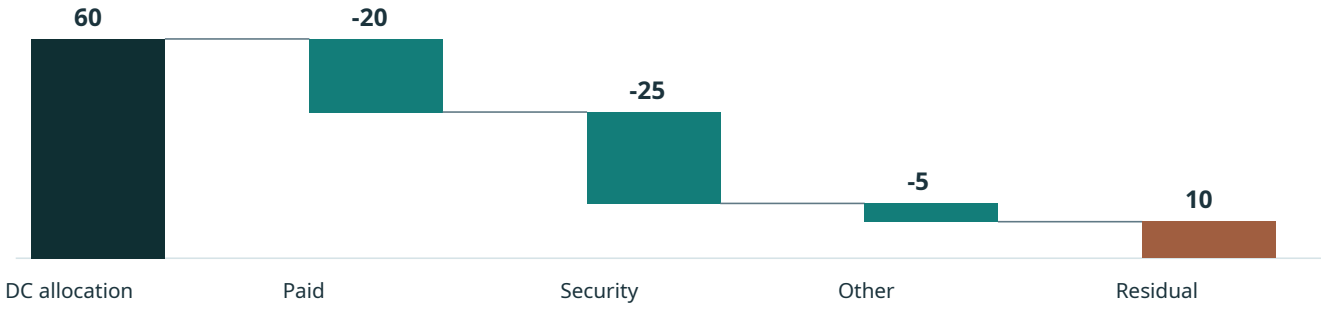
09 / STRANDED COSTS

Collateral does not guarantee full cost recovery

Illustrative stress test | Separate a fair allocation from collection after customer default.

Assume total infrastructure cost of 100: 40 legitimately allocated to other users and 60 to the data center. If the data center fails after paying 20, its remaining obligation is 40. The bridge assumes collection of 25 from security and 5 from other recoveries. No actual project or default-recovery estimate is implied.

Illustrative recovery bridge (arbitrary units)



Conditional outcome	Total DC recovery	Unrecovered
All remaining 40 collected	60	0
Security 25 + other recovery 5	50	10
Only security of 10 collected	30	30

Arbitrary monetary units; discounting, collection time and taxes excluded. Security collects part of the remaining 40: it is not added again to allocated cost of 60.

The residual 10 is not automatically a household bill

Reuse of assets, a replacement customer, insurance, guarantees, utility loss absorption and regulatory cost recovery can change the outcome. Fees and prior tariff recoveries also need reconciliation to prevent duplicate recovery. A dedicated rate class and a guarantee cannot by themselves justify zero residual exposure.

> **The complete protection chain**
>
> **Causal allocation → contractual liability → enforceable security → actual collection → regulatory treatment of the residual. Each link must work before cost shifting can be judged contained.**

10 / CAPACITY IS A SEPARATE BILL

PJM adds an adequacy bill, not a network invoice

29 October 2026 revised proposal: trace both the supply solution and its cost pathway.

Proposal scope

PJM proposes one-time procurement against an approximately 6,800 MW generation-capacity shortfall for 2028/29. The revised filing addresses LSE allocation based on large-load growth, credit and exit responsibility, with a target launch of 1 March 2027. The shortfall will be recalculated. [9]

Load growth
Estimate regional additions

›

Wholesale duty
Allocate procurement cost to LSEs

›

Final bill
Apply state tariffs and customer contracts

Observation point	Economic significance
Forecast → allocation	Reconciliation matters when allocated costs outlive a load forecast that does not materialize.
Long-term supply	Up to 15-year resource commitments can support investment, while creating a corresponding buyer obligation. [9]
Supplier / LSE exit	Follow who retains the procurement obligation when the supply relationship changes.
Retail pass-through	Allocation to an LSE does not prove that data centers alone bear the ultimate bill.

Supplier revenue visibility and the customer's fixed commitment are opposite sides of the same contract. Stronger rules do not guarantee higher profits for every power supplier: selection, construction cost, operations and payment security determine the economic result.

Keep the units separate

Capacity MW, network construction dollars and energy dollars per MWh measure different things. Procurement volume cannot be translated directly into equipment revenue or a data center's annual electricity expense.

11 / FLEXIBILITY HAS A PRICE

Flexible demand is a trade—not free connection

Reliability priority, interruption losses and operational controls determine the value.

Case / status	Choice offered or proposed	Associated price
SPP CHILLS [10]	Approved as-available service; one-to-seven-year term	Lower priority than firm service; possible curtailment
CAISO Large Loads [3]	Board-approved connection and service framework	Federal approval and detailed operating terms remain distinct
Google response [12]	1 GW incorporated into long-term utility contracts	Contracted capacity, not cumulative dispatch or proven savings

Net value of flexibility = earlier operating profit + avoided cost − workload losses − control / storage investment − penalty risk

Deferrable training and real-time inference or customer services have different curtailment costs. Moving work can still incur latency, data-transfer and reserved-GPU costs. Equal curtailed MW need not imply equal foregone business value.

Commissioner Rosner's 9 October concurrence on PJM IRAS discusses curtailment priorities and capacity-market signals. Flexibility proposals are not approved on interchangeable terms; non-firm service and paid demand response should not be double-counted. [11]

Early access must be valued against a feasible alternative

Conditional service may enable earlier operations than waiting for firm supply. Its benefit falls when tenants must be compensated or workloads shifted to more expensive capacity. The comparator is a project's actual alternative, not an imaginary uninterrupted power price.

> **On-site generation and batteries face the same test**
>
> **Lower normal grid use can leave substantial backup obligations when a generator trips. Evaluate batteries by verified peak reduction, duration and controllability—not installed capacity alone.** [4] [16]

12 / WHO GAINS, WHO PAYS

The advantage is the ability to carry the contract

TradeLens analysis | The same rule produces different outcomes across funding and business models.

Participant	Potential benefit	Remaining exposure
Strong integrated sponsor	Relative advantage in security, long commitments and workload location	AI monetization may lag power obligations
Independent developer / colo	Differentiation through secured power and creditworthy tenants	Utility commitment can outlast or exceed tenant backing
Utility / grid owner	More collectible investment and predictable receipts	Approval, disallowed costs, default and construction delays
Existing customers	Causal allocation and credit support reduce exposure	Shared residuals, wholesale prices and forecast error
Korean equipment / EPC	Delivery opportunities from funded expansion	Announced or requested MW are not firm equipment orders

Read the quality of binding contracts, not just requested MW

AEP Ohio reported 5,642 MW of binding contracts under DCT as of 12 February 2026. This is a company-reported contracted-load measure, not energized demand or the value of equipment already ordered. [13]

Demand intent
Site, plan and application

›

Executable contract
Credit, security and tenants

›

Physical conversion
Construction, delivery and operation

Implication for Korean suppliers

Start with financed contracts, construction conditions, equipment delivery schedules and payment terms—not announced campus size. This report does not infer undisclosed Korean company orders, customers or margins.

13 / OUTLOOK & MONITORING

Selective buildout—not a blanket stop

A conditional industrial assessment, not a forecast of individual orders, revenue or share prices.

Path	Conditions that must coincide	Economic outcome
Base: execution-led	Long contracts and security align with committed tenant demand	Speculative reservations shrink; stronger sponsors keep investing
Better: use existing assets	Verified flexibility, joint studies and staged connections	Less incremental construction and waiting cost; broader participation
Stress: failed recovery	Load fails to arrive, tenants depart, security proves insufficient	Stranded cost, renegotiation and tariff disputes increase

Higher initial obligations may redirect investment toward stronger credit, credible occupancy and faster energization rather than eliminate it. If improved connections and operations substantially lower incremental cost, smaller sponsors can also benefit. National-laboratory work explores connection and storage solutions beyond simply building more infrastructure. [14] [16]

Next observation	Evidence that strengthens or changes the view
16 / 20 Nov 2026 [1]	How specifically regional filings define recovery, disclosure and credit
1 Jan 2027: Virginia [7]	How new-contract rules, exemptions and allocation work together
1 Mar 2027: PJM target [9]	Approval conditions, revised procurement needs and ultimate cost bearers
Project follow-up	Application-to-contract-to-operation conversion; exits, security collection and reassignment

Final assessment

The ultimate payer is determined by cost causation, retail allocation, contract duration and post-default collection—not by who announces the capital expenditure. Consumer protection and AI infrastructure growth can coexist, but the link is enforceable obligations and actual operation, not promised demand alone.

14 / SOURCE REGISTER

Sources and original documents 1/2

Teal reference numbers and source titles link directly to the original documents.

01. FERC | Cost Transparency and Customer Protection

OPEN SOURCE

As of 7 Nov 2026 · Official process guide; six regional proceedings and deadlines

02. FERC | NYISO Order to Show Cause, EL26-69-000

OPEN SOURCE

18 Jun 2026 · Order, paragraphs 83–91: cost recovery, credit and offsets

03. CAISO | Large Loads Initiative: Proposal and Decision Status

OPEN SOURCE

28 and 30 Oct 2026 · Board approval and revised tariff; federal filing still scheduled

04. Ohio Power / AEP Ohio | Data Center Tariff: Official Implementation Guide

OPEN SOURCE

As of 7 Nov 2026 · Contract term, LOA, collateral and minimum-demand schedule

05. Ohio Power / AEP Ohio | Schedule DCT in the Ohio Power Tariff Book

OPEN SOURCE

Effective 10 Apr 2026 · Sheets 223-3 to 223-7: demand formula and contract obligations

06. PUCO | PUCO Orders AEP Ohio to Create Data Center Tariff

OPEN SOURCE

9 Jul 2025 · Regulator decision summary; rationale for dedicated tariff

07. Virginia SCC | Dominion Biennial Review Order, PUR-2025-00058

OPEN SOURCE

25 Nov 2025 · Order, pp. 23–26: GS-5, 14-year term, charge floors and exceptions

08. Virginia SCC | SCC Data Center Initiatives

OPEN SOURCE

Feb 2026 · Fact sheet; separate rate class, allocation and security

Source status is limited to the stated date and jurisdiction. Orders, proposals, company claims and TradeLens calculations are distinct. A tariff schedule is not an all-in quote for any individual site.

15 / SOURCE REGISTER

Sources and original documents 2/2

Teal reference numbers and source titles link directly to the original documents.

09. PJM | Amended Reliability Backstop Procurement Proposal OPEN SOURCE

29 Oct 2026 · Proposal; capacity shortfall, allocation to LSEs and 2027 timetable

10. FERC / SPP | Order Accepting SPP Conditional Large-Load Service OPEN SOURCE

5 Jun 2026 · ER26-1323, pp. 5–7: one-to-seven-year term and curtailment

11. FERC | Commissioner Rosner Concurrence on PJM IRAS OPEN SOURCE

9 Oct 2026 · Concurrence; curtailment priority and capacity-market incentives

12. Google | A 1 GW Milestone in Data Center Demand Response OPEN SOURCE

19 Mar 2026 · Company disclosure; contracted flexibility, not realized dispatch

13. AEP Ohio | Update to PUCO on Binding Data Center Load OPEN SOURCE

13 Feb 2026 · Company disclosure; 5,642 MW signed under DCT as of 12 Feb

14. Lawrence Berkeley National Laboratory | Beyond the Bottleneck: Accelerating Large Load Connections OPEN SOURCE

11 Jun 2026 · National laboratory research; planning and interconnection solutions

15. PUCO | Protecting Customers When Data Centers Return to Default Supply OPEN SOURCE

5 Aug 2026 · Regulator release; 180-day notice and dedicated energy procurement

16. Pacific Northwest National Laboratory | Storing Affordability: Battery Storage and Data Center Cost Shifts OPEN SOURCE

22 Sep 2026 · National laboratory study; peaks, cost allocation and residual risk

Source status is limited to the stated date and jurisdiction. Orders, proposals, company claims and TradeLens calculations are distinct. A tariff schedule is not an all-in quote for any individual site.

16 / METHODOLOGY & USE

Methodology, disclaimer and use

Reported facts, approved rules, proposals, analysis and illustrations are distinguished.

Item	Basis
Scope / date	7 Nov 2026. U.S. large-load interconnection, tariffs and cost allocation. Approved, effective and proposed arrangements are distinguished.
Sources	FERC and state orders, grid-operator and utility publications, and national-laboratory research. Not legal advice or a site-specific electricity quotation.
Calculations	Page 7 calculates a published demand-floor structure. Pages 9 and 10 use illustrative prices and recovery assumptions, not actual tariff or recovery forecasts.
Units	MW is power; MWh is energy consumed. Construction, capacity procurement, energy and collateral are not double-counted. Rounding may cause differences.
Outlook	Proposed 2027 dates differ from approved effective dates. No undisclosed orders, margins, customer relationships, price targets or trading recommendations are inferred.

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