

From Load Contract to Grid Asset

How dispatchable demand can accelerate speed-to-power while reducing capital, reliability and regulatory risk.

Large-load growth is creating a new speed-to-power challenge for U.S. utilities: how to connect unprecedented new demand fast enough to support economic growth, without overbuilding the system or transferring excessive risk to existing customers. Flexible-load contracts can become part of the answer, but only when flexibility is measurable, dispatchable and auditable. The challenge is therefore not simply to contract new demand, but to turn contractual flexibility into an operational grid capability that planning, operations, finance and regulators can rely on.

A. At a glance

10% a year

System retail sales are forecast to grow at approximately 10% annually through 2030. If that rate were sustained for five years, simple compounding would imply roughly 61% cumulative growth; this is an arithmetic illustration, not a separate company forecast. Weather-adjusted retail energy sales across the regional electric system grew 1.7% in 2025. [\[1\]](#)[\[2\]](#)

9,885 MW and \$16.7 billion

The state commission certified 9,885 MW of resources on 19 December 2025; the issuer later disclosed approximately \$16.7 billion of approved owned projects and related transmission investment, excluding allowance for funds used during construction. [\[2\]](#)[\[3\]](#)

3,200 MW, phased 2028–2032

One AI campus has contracted for 3.2 GW. That is roughly 32% of the 9,885 MW resource portfolio certified in December 2025; this is a scale comparison only, not a statement that the load and resource portfolio are directly substitutable. [\[3\]](#)[\[4\]](#)[\[5\]](#)

Up to 1,000 MW flexible

The customer has committed up to 1 GW of demand response, approximately 31% of the campus commitment. At maximum response, the implied residual demand is 2.2 GW; public sources do not disclose notice, duration, call frequency, performance testing or non-performance remedies. [\[4\]](#)[\[5\]](#)

\$950 million a year, 2029–2031

The regulated utility projects that incremental revenue from large-load customers will provide approximately \$950 million per year in customer benefits, or \$2.847 billion over 2029–2031. [\[4\]](#)[\[6\]](#)

A3/A/A, stable

A May 2026 debt offering carried expected stable ratings of A3, A and A. No public rating action was found that attributes a change to this contract or its flexible tranche. [\[7\]](#)

B. What the evidence says

The forecast has become a financing assumption

The focal regional electric system has moved from a historic planning environment of roughly 0–1% annual load growth to a disclosed forecast of approximately 10% a year through 2030. The issuer's 2026 proxy also links that growth directly to data centers. Across the electric operating companies, retail sales grew 2.5% in 2025, weather-normalized commercial sales grew 4.9% and data-center sales grew roughly 20%, while industrial sales declined 0.9% and overall system sales grew 1.7%. Total retail sales growth at the primary operating company was 2.5% for the year. Across the broader electric system, total sales grew 1.7%. [1][2]

Those figures describe three different things: an actual sales base, a contracted ramp and a forecast of future load. Treating them as one number creates the central capital risk. At 10% annual growth, five years of compounding produces 1.61 times the starting sales volume. The physical system has to be committed before the forecast can be observed, while data-center technology, project schedules and customer portfolios can change faster than power plants and transmission assets can be repurposed.

The commission's December 2025 decision certified 9,885 MW and paired the resource approval with customer-protection measures intended to address the risk that large-load growth may materialize differently from forecast [3]. The subsequent Form 10-K disclosed approximately \$16.7 billion for approved owned projects and related transmission investment, excluding financing during construction. [2] That is the verified pain attached to forecast error. No source reviewed assigns a verified dollar cost to the 1,000 MW flexible tranche itself; any proportional capital estimate would be an unsupported extrapolation and is therefore excluded.

The contract is large enough to change the planning problem

The AI campus contract is for 3,200 MW delivered in phases from 2028 to 2032. Its maximum 1,000 MW demand-response commitment equals 31.25% of the contracted peak, leaving an implied 2,200 MW residual if the full tranche is available and called. The 3,200 MW commitment equals 32.37% of the 9,885 MW certified portfolio; the flexible tranche equals 10.12% of that total. These ratios are arithmetic derived from disclosed figures, not estimates of capacity credit.

[\[3\]](#)[\[4\]](#)[\[5\]](#)



This distinction matters. A 1,000 MW clause is not automatically equivalent to a 1,000 MW peaking plant, battery or firm purchase. Its capacity value depends on when it is available, how quickly it responds, how long it can sustain reduction, how often it may be called, whether consecutive events are permitted, what happens during extreme weather, how the baseline is calculated and what remedy applies when performance falls short. Federal advisory guidance identifies these same parameters: available MW, response frequency, duration, ramp rate, ability to shift rather than shed, performance under extremes and uncertainty in response magnitude and speed. [\[9\]](#)

The public descriptions establish that the utility can reduce service during high-demand periods and that the agreement runs for 25 years. They do not disclose the operating envelope or settlement mechanics. [\[4\]](#)[\[5\]](#)[\[20\]](#) The gap is decisive. Until those terms are translated into planning and operating rules, the flexible tranche is a commercial option with an unknown capacity accreditation, not a verified resource.

Reliability value is temporal, locational and conditional

The 2025 NERC long-term assessment says SERC-Central reserve margins are expected to decline over the next decade as load growth and winter weather sensitivity increase. It identifies data centers and other large commercial loads as a forecasting and transmission-development risk because of short lead times and uncertain scalability. [10] NERC's 2025 State of Reliability report adds an operational concern: rapid load changes can affect balancing, frequency and voltage stability, while current models do not accurately represent data-center behavior. [11]

That evidence does not mean large loads are inherently harmful. Lawrence Berkeley National Laboratory identifies four flexibility mechanisms: temporal or geographic workload shifting, core-facility adjustments, storage and onsite generation. It also warns that demand flexibility is an immediate integration tool, not a substitute for the long-term need for bulk supply. [12] EPRI's DCFlex programme has reported a UK demonstration in which selected AI data-center loads were reduced by up to 30–40% within seconds without disrupting critical workloads; this is a demonstration result, not a transferable capacity guarantee. [13]

The planning question is therefore not “Is the customer flexible?” It is “Which megawatts are available under which grid conditions, at which node, for how long, with what rebound effect and with what evidence?” A reduction after the system peak, at a location that does not relieve the constrained facility, or followed by a synchronized rebound may have much less capital value than its nameplate size suggests.



Cost allocation has moved from principle to contract design

The state framework for new customers above 100 MW requires long contracts, minimum bills, collateral and termination payments. Public company materials describe terms of 15 to 25 years, while the 2026 proxy says nearly all data-center contracts have minimum terms of at least 15 years and are designed to cover at least 100% of annual incremental cost to serve, including generation, transmission, operations and maintenance, and cost of capital. [6][14]

Comparator jurisdictions show how quickly this is becoming a national design discipline. Ohio's approved tariff requires reimbursement of 100% of buildout cost if a customer cancels or delays more than 12 months before energization; it also sets a contract term equal to a ramp period of up to four years plus eight years and requires minimum demand charges that cannot exceed 85% of contract capacity. [15] Virginia's commission created a separate large-load class with a minimum 14-year service obligation and minimum payments equal to 85% of contracted transmission and distribution demand and 60% of generation demand, among other protections. [16]

These structures solve only part of the problem. Minimum bills and exit fees protect revenue after infrastructure is committed. Dispatchable flexibility can reduce what must be committed in the first place, but only if the utility and regulator can observe and credit it. The two instruments should be integrated:

financial assurance protects against non-arrival

operational assurance protects against peak coincidence.

The downside protection has a time boundary

The original December 2025 settlement required at least \$556 million of annual downward rate pressure in 2029–2031. After the 3.2 GW contract was approved, the public commitment increased to approximately \$950 million a year, or \$2.847 billion over those three years. [2][4] The current base-rate freeze runs through 2028, and the next base-rate case is expected in 2028. [1][3]

The verified regulatory exposure is therefore not a fine. It is a sequence of decisions: the 2028 rate case, the 2029–2031 backstop, and the treatment of costs after the protection window ends. No public source reviewed quantifies a regulatory disallowance tied to failure of the 1,000 MW tranche. No public source discloses a performance penalty payable by the large-load customer for a missed curtailment. These are declared gaps.

Protection-window test

The public benefit window ends before the load ramp does.



The credit position is similarly bounded. A May 2026 debt offering carried expected stable ratings of A3/A/A. [7] That provides a contemporaneous credit snapshot, not evidence that the large-load contract has no rating effect. No rating-agency source reviewed attributes an upgrade, downgrade or outlook revision to the exceptional-load contract. The rating impact is therefore “none publicly identified,” while the financing scale remains visible through the \$81 billion system capital plan and the \$16.7 billion certified project disclosure. [1][2]

The regulatory perimeter is still moving

On 18 June 2026, FERC ordered six regional grid operators to justify or reform tariffs for large loads. The orders identified five areas: study processes, cost-shift prevention and transparency, co-location, flexible transmission service, and processes for generation serving proximate or co-located loads. Each operator had 60 days to justify existing rules or file changes, and 30 days to explain how adequate generation would be available. [17] The focal operating utility is outside an organized RTO market, so these orders are a comparator, not a direct tariff mandate. Their relevance is directional: federal policy is moving toward explicit cost-recovery agreements and flexible service definitions.

The unresolved national issue is whether flexibility remains a bilateral promise or becomes an accredited system resource. By 2032, boards and commissions will need a record showing not only that the customer promised 1,000 MW, but how much was available, dispatched, delivered and credited against capital decisions.



C. Implications and scenarios

The Flexibility-to-Capital-Risk Ladder

Turning flexible demand into a grid asset requires more than a contract clause. The Flexibility-to-Capital-Risk Ladder shows the evidence utilities need to move from a commercial promise to an operational capability that can support planning, dispatch and capital decisions. Each rung reduces uncertainty before flexibility can safely contribute to speed-to-power or capital deferral.

Rung	Evidence required	Capital interpretation	Public status for the 1,000 MW tranche
1 Named	Contracted MW and term	Commercial option exists	1,000 MW maximum; 25-year agreement [4][5][20]
2 Bounded	Notice, duration, frequency, season, rebound	Operating envelope can be modeled	Not publicly disclosed
3 Observable	Metering, telemetry, baseline and data rights	Performance can be measured	Not publicly disclosed
4 Callable	Dispatch authority, communications, testing and override rules	Control room can depend on response	General curtailment right disclosed; protocol not public
5 Enforceable	Non-performance remedy, collateral link and settlement	Counterparty bears failure risk	No verified public monetary remedy found
6 Accredited	Planning capacity value and regulator-approved treatment	Capital can be deferred or avoided	No public accreditation found

Four strategic postures

1 Forecast-led build

Capital follows the full load forecast and flexibility is treated as upside. This maximizes speed to power but leaves the greatest exposure if ramp schedules slip. The verified scale of capital exposed is the \$16.7 billion approved project and transmission program; no public source isolates the cost caused by this customer. [\[2\]](#)

2 Contract-protected build

Minimum bills, collateral and termination payments cover incremental cost, but planning continues to treat demand as firm. This protects revenue and ratepayers better than a standard tariff, yet it may still build capacity that a dispatchable load could have avoided. NTT DATA's reading is that the current public framework appears closest to this posture. [\[6\]](#)[\[14\]](#)

3 Accredited-flex build

Capital gates are linked to verified ramp milestones and an accredited flexible tranche. The 1,000 MW is credited only to the extent supported by dispatch tests, telemetry and regulator-approved methodology. This aligns finance, operations and regulation without pretending flexibility eliminates the need for new supply.

4 Flex-first interconnection

A customer accepts explicitly non-firm service to connect earlier with fewer network upgrades. This may reduce time to power, but it transfers operational complexity to the customer and requires a credible workload architecture. FERC's 2026 orders make this posture increasingly relevant in organized markets. [\[17\]](#)



D. NTT DATA point of view

At NTT DATA, we believe the opportunity is to turn flexible-load contracts into an operational capability that utilities can safely use to accelerate connection, manage grid constraints and reduce capital uncertainty.

The challenge is that no single system owns this capability today. Commercial teams manage contracted ramps and commitments; planners manage forecasts and infrastructure requirements; control rooms manage grid conditions and dispatch; metering teams measure performance; finance manages capital gates; and regulatory teams maintain the evidentiary record. Flexibility can lose its value as it moves between these functions.

Connecting these layers requires a digital and operational model that brings together load and flexibility forecasting, digital twins and real-time grid data, telemetry and dispatch workflows, performance measurement, AI-enabled decision support and auditable evidence.

The objective is not to assign capacity value by assertion. It is to create the data, controls and operational evidence required to determine which megawatts can genuinely be relied upon, under which conditions, and what this means for connection timing, infrastructure decisions and capital exposure.

The Flexibility-to-Capital-Risk Ladder would function as the control model. Each load tranche would carry firmness, notice, duration, call limits, rebound profile, infrastructure dependency, collateral, stranded-cost bearer and regulatory treatment. Capital committees could then distinguish three quantities that are often collapsed:

requested MW



contract-backed MW



accredited firm-equivalent MW.



The opportunity for utilities is not to treat flexibility as a substitute for generation or network investment. It is to make flexibility sufficiently measurable, dispatchable and auditable that it can become another instrument in the planning and operating toolkit.

NTT DATA's role is to provide the digital and operational layer that connects contract, forecast, grid conditions, telemetry, dispatch, performance and evidence — helping utilities accelerate speed-to-power while making better-informed reliability and capital decisions.

WHAT IT TAKES TO TURN FLEXIBILITY INTO AN OPERATIONAL ASSET

1. Forecast demand & flexibility

Model load ramps, demand profiles, peak coincidence and flexibility scenarios.

Powered by: [AI-Enabled Grid Operations](#)

2. Connect load & grid conditions

Combine digital twins, topology, asset data and real-time information to determine where flexibility can relieve system constraints.

Powered by: [Digital Twin Connectivity for Real-Time Utility Operations](#)

3. Operationalize dispatch & performance

Connect telemetry, dispatch, customer response, baselines and exception workflows to make flexibility measurable and callable.

Powered by: [AI-Enabled Grid Operations](#)

4. Create an auditable evidence chain

Link forecasts, contract commitments, dispatch events, measured response and capital decisions into a reproducible record.

Powered by: [AI for Regulatory & Operational Compliance](#)



E. What leaders should do

- 1 Separate the three megawatts.**

Report requested, contract-backed and accredited firm-equivalent demand separately in every resource plan and capital paper.
- 2 Make flexibility testable before it is financeable.**

Define notice, duration, frequency, ramp rate, rebound, seasonal availability, baseline, telemetry and remedies; run witnessed tests before assigning capacity credit.
- 3 Link capital gates to load gates.**

Release generation and network capital against verified customer milestones, collateral and measured performance, with cancel, defer, repurpose and resale options recorded.
- 4 Create one regulatory evidence chain.**

Preserve the forecast vintage, contract term, dispatch event, performance result, settlement and capital consequence in a record that commissioners and auditors can reproduce.
- 5 Design the 2032 handoff now.**

The current publicly disclosed benefit projection runs through 2031 while load delivery continues into 2032 and the contract extends much longer. Ensure the post-2031 cost-allocation and recovery treatment is explicit in governance and regulator-facing evidence before the protection window closes.



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