Grid under pressure

Indicators of resilience, risk, and market rebalancing for power system planning

February 2026

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Introduction

A system under stress

Power systems across North America are no longer being tested at the margins—they are being stress-tested at the system level. Load growth (including large-load concentration), tightening reserve margins, interconnection and transmission bottlenecks, and higher capital costs are converging in ways that make reliability and affordability inseparable.

What looked like isolated issues a few years ago—capacity market volatility, North American Electric Reliability Corporation (NERC) compliance trends, distributed energy resource (DER) participation rules, natural gas contracting constraints—are now interacting. The result is a grid that is rebalancing under pressure, where resilience is being reinforced in some places, while risks are accumulating in others and market/ratemaking frameworks are struggling to keep pace.

The procurement-performance gap

The most important takeaway is that the system is increasingly revealing a gap between procurement optics and deliverable performance. Recent market outcomes and policy responses underscore that price signals alone may not be sufficient to bring forward firm capacity at the pace required, and that reforms will unfold on implementation timelines measured in years - driven by transmission approvals, queue throughput, verification requirements, and planning institutions that move at the speed of defensible accreditation (not aspiration).

This dynamic is showing up directly in capacity and large-load policy debates, where “flexibility” is frequently positioned as a release valve, but planners continue to treat flexibility as non-firm unless it is enforceable, verifiable, and defensible under stress conditions.

Regulatory evolution and affordability pressures

At the same time, oversight and regulatory context are shifting. NERC’s posture has evolved from a predominantly compliance-driven model to a more strategic, risk-based approach that prioritizes resilience, modernization, and emerging threats (while still reinforcing that compliance is foundational). NERC sets mandatory reliability standards to prevent cascading blackouts.

In parallel, affordability has moved from a background concern to a front-line constraint: even where evidence of a uniform “national” affordability crisis is mixed, the perception and political salience of bill impacts are already reshaping commission posture, ratemaking scrutiny, and expectations for spending discipline.

Natural gas: The grid’s pressure point

Finally, natural gas is emerging as the grid’s pressure point. As demand rises, supply and infrastructure expansion are increasingly gated by durable forward price and contracting signals—meaning the system may rebalance through higher volatility, tighter firmness terms, and higher required returns rather than smooth capacity expansion. That tension feeds directly back into both reliability planning and affordability outcomes, especially as more stakeholders compete for firm deliverability.

The forces reshaping the utility sector

Five forces across these key themes are fundamentally reshaping how utilities plan, invest, and operate in North American power markets.

The procurement-performance gap

1	**Political intervention becomes a market reality**	Recent developments in PJM show how capacity, scarcity, and affordability concerns could prompt government action.
2	**Flexibility-centered large load policies overlook recent lessons**	What DERs can teach us about data centers: large load flexibility policy efforts through the lens of FERC Order 2222 expectations and implementation realities.

Regulatory evolution and affordability pressures

3	**NERC's evolution: Strategic risk management over compliance**	NERC has transitioned from a predominantly compliance-driven oversight model to a strategic, risk-based approach that prioritizes resilience, modernization, and emerging threats while maintaining compliance as a foundational requirement.
4	**The affordability risk for utilities**	Effective engagement and understanding regional context can help mitigate risks and position for success.

From capacity expansion to constraint management

5	**Natural gas: The grid's impending pressure point**	As electric demand grows, natural gas has become the system's pressure point—critical to reliability but slow to expand without clear price signals, and increasingly central to planning, contracting, and capital decisions that balance cost and resilience.

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For each force, we identify a set of **indicators of change** that we are tracking to monitor whether stress is intensifying or easing, where incentives are aligning or breaking down, and what that implies for planning, contracting, market design, and regulatory strategy.

Industry perspective on grid stress

To pressure-test our narrative, we conducted a targeted survey of grid leaders, focusing on the most credible near-term risks and realistic firm-capacity pathways into the 2030s. The insights reinforce the core thesis of this analysis: the grid is being stress-tested in real time, and the most important signals are not isolated. Reliability, fuel deliverability, supply-chain constraints, and market design are increasingly moving together.

Reliability confidence: "manageability with vulnerabilities"

Nearly 80% indicated they are only somewhat confident that the industry can maintain reliable service under rising extreme weather and surging demand. The remainder were split between neutral and somewhat concerned.

This view reflects confidence in existing tools and coordination, but persistent exposure by region, resource type, and event severity. This means the focus is shifting to two key questions: where are risks concentrating and what solutions can be delivered on planning timelines?

Top reliability risks: Operational, not abstract

The highest-concern risks over the next 3–5 years were gas supply dependency and fuel deliverability, followed by inverter-based resource instability. Climate-driven extremes, cyber threats, aging infrastructure, and supply-chain constraints ranked close behind.

These are operational risks that can surface quickly through winter firmness challenges, summer peak stress, and system disturbances - not abstract "long-term transition" concerns. The shift: from planning adequacy to operational resilience as the binding constraint.

Future capacity expectations: Storage dominates, options narrow

Responses on what will meaningfully contribute to baseload or firm capacity by the late 2030s highlight a clear directional shift. Storage—especially long-duration energy storage—stands out as the dominant clean option expected to have significant impact. Small modular reactors (SMRs) were viewed as a secondary contributor, material but less uniformly certain.

By contrast, other clean firm pathways were generally viewed as having limited system-wide impact by that timeframe. These include carbon capture and storage, hydrogen/ammonia-fueled generation, geothermal, and bioenergy/renewable natural gas.

The message is less "clean energy won't matter" and more "the set of clean firm options the market expects to scale meaningfully is narrowing." The system is likely to rely on a mix of storage plus gas (with tighter deliverability requirements), with nuclear as an upside case rather than a base assumption.

The procurement-performance gap

Political intervention becomes a market reality

Authors

Emma Nicholson, PhD
Principal

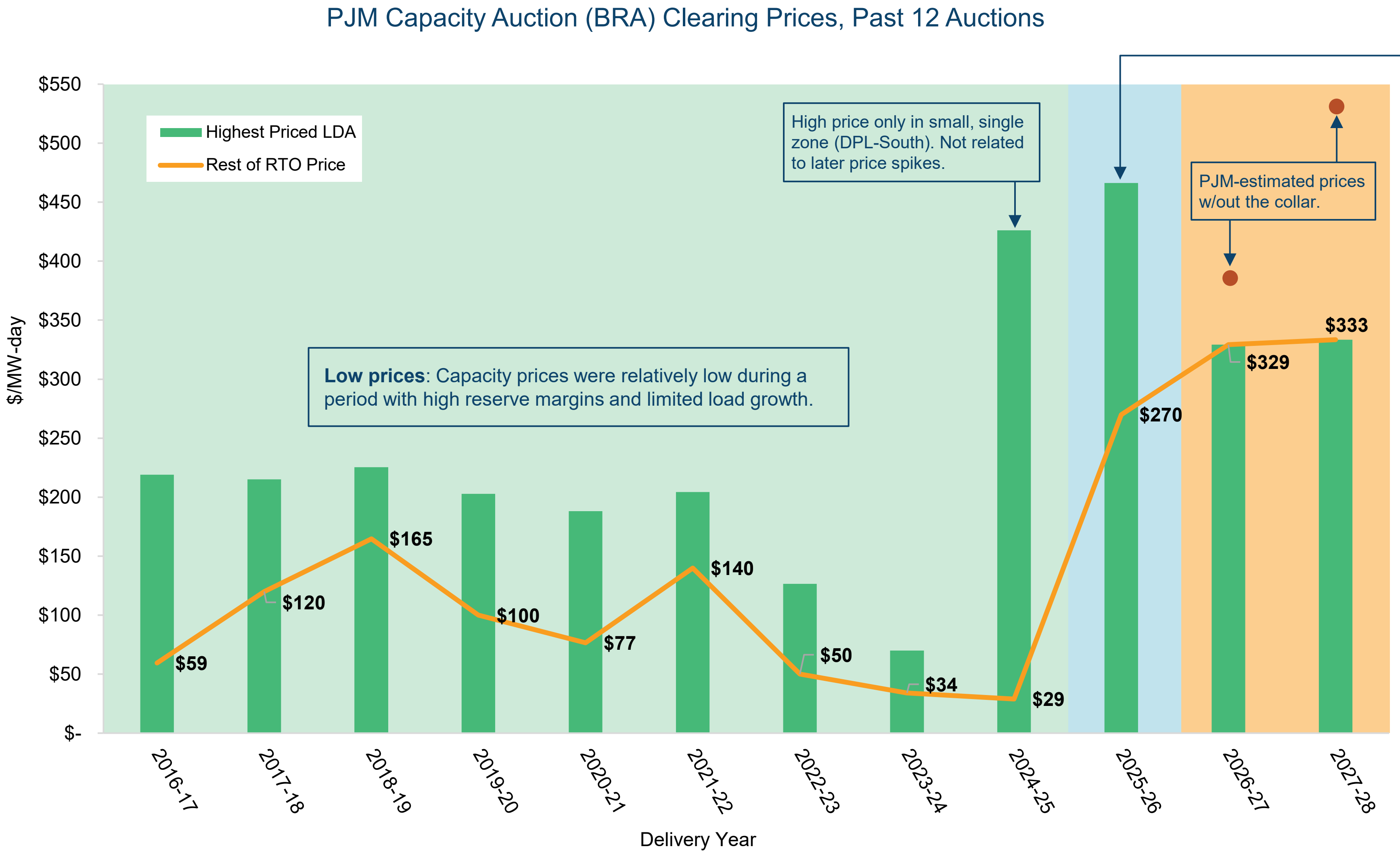
Jeff Plewes
Principal

Indicators of change

These indicators help us track actions that could trigger direct political or regulatory intervention in wholesale electricity markets

- **Customer cost impacts:** Significant expected cost increases for customers.
- **Federal and state regulatory or legislative activity**: Actions by state governors, state legislators, or state public utility commissions to review wholesale market design.
- **Degraded reliability:** A declining reserve margin that can threaten electric reliability or indicate a wholesale market is not functioning properly.
- **Slow generation deployment:** A market that cannot deploy new generation fast enough to meet projected load growth.

PJM capacity prices surged after an extended period of low prices, leading to significant attention and, ultimately, intervention



Price spikes: Prices spiked across PJM in the 2025/26 BRA (held Feb '24), and particularly in BGE and Dominion zones. Drivers included thermal resource retirements, minimal new entry, and surge in load growth, largely from data centers.

Regulatory intervention to manage costs:

- Complaints and political response led to capacity market rules changes for the DY 2026/27 and 2027/28 auctions, including a new price "collar" (cap and floor).
- Continued load growth, while new supply entry was minimal.
- The price cap was hit in each auction, with PJM estimating much higher uncapped prices in the 2027/28 BRA.

PJM's recent capacity auction hit record prices while clearing short of the reliability requirement for the first time in history

Record high price *(that could have been higher)*	• The December 2025 capacity auction for DY 2027/28 cleared at the cap of **$333/MW-day** in each zone. • PJM said the auction would have cleared at **$523/MW-day** without the "collar" (price cap and floor). Dominion would have been slightly higher.
Failure to achieve reliability target	• The BRA fell short of the resource adequacy requirement by 6.6 GW UCAP, amounting to a 14.8% installed reserve margin that was **5.2% below** PJM's 20% target. • After the auction, PJM lowered the 2027/28 load forecast, reducing the expected capacity shortage.
Limited Supply Response	• Only **~350 MW UCAP of new capacity** and ~425 MW UCAP from uprates was procured (out of a total of 134 GW).

How did we get here?

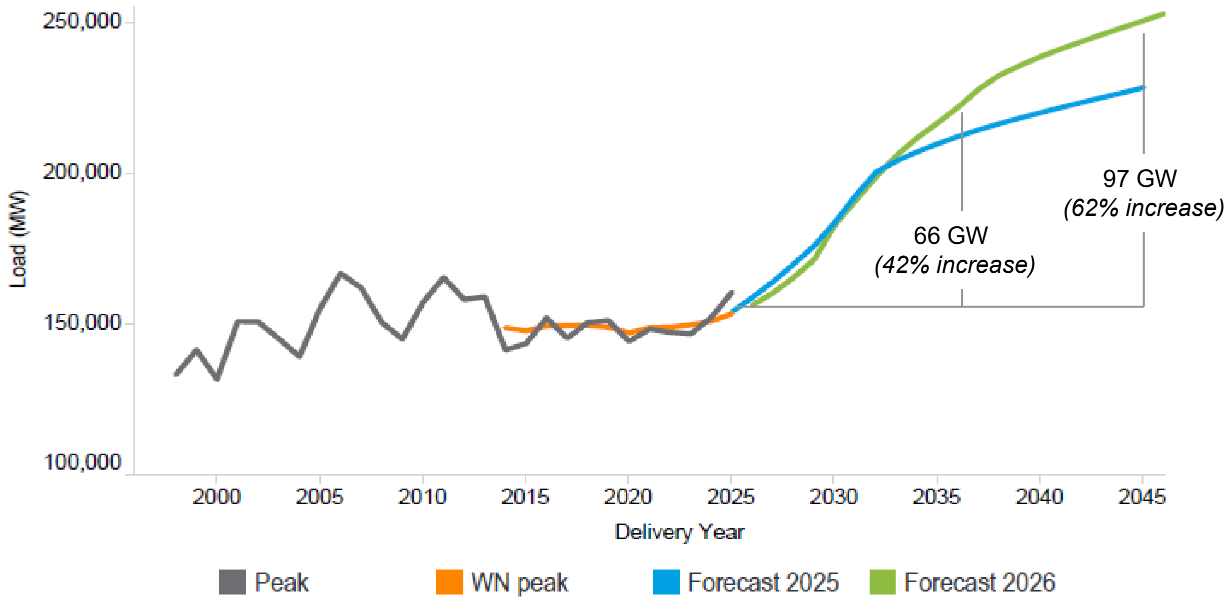
Drastic load growth	***Limited new entry***	***Resource retirements***

Each of these drivers is addressed in the following slides.

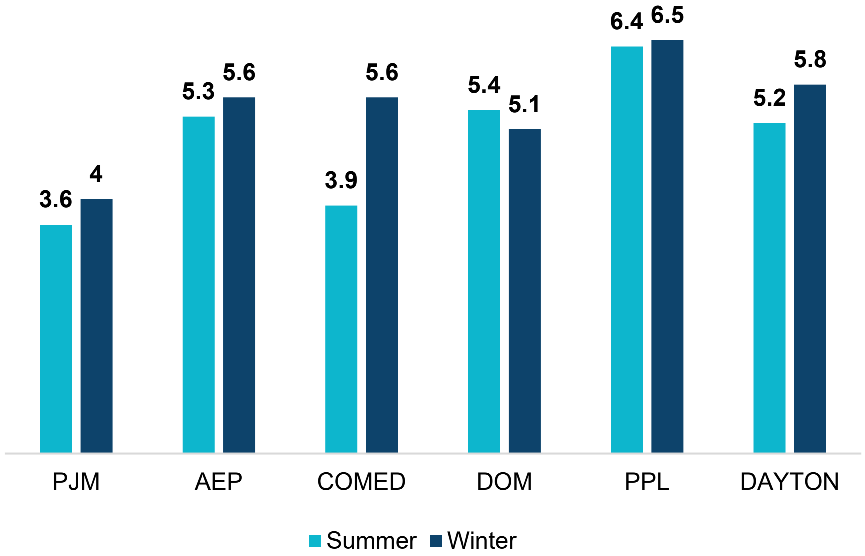
Load growth: Data center demand has driven a sharp increase in load forecasts, although forecasts are uncertain and constantly changing

PJM January 2026 load forecast

Summer Peak Demand (MW)



Data center load growth (%), 2026-2036



Compared to the 2025 forecast, PJM's 2026 load forecast saw slightly lower peaks in near term, but higher peaks starting in mid-2030s.

Load growth in PJM in the next 10 years is highly concentrated in a handful of load zones.

Source: PJM 2026 Load Forecast Report, Jan. 14, 2026

New entry: New resource entry has been slow in PJM due to rising capital costs, equipment backlogs, and delays in siting, permitting, and generator interconnection

Challenges to new entry – not expected to change in the near term

Increased capital costs + Equipment backlogs

Costs remain very high with no near-term signs of reductions and supply chains likely challenged for years to come.

Siting and permitting challenges

Some improvement at state levels but overall remains a challenge and federal solutions remain elusive.

Generator interconnection - delays

Significant improvements with recent reforms, but challenges remain.

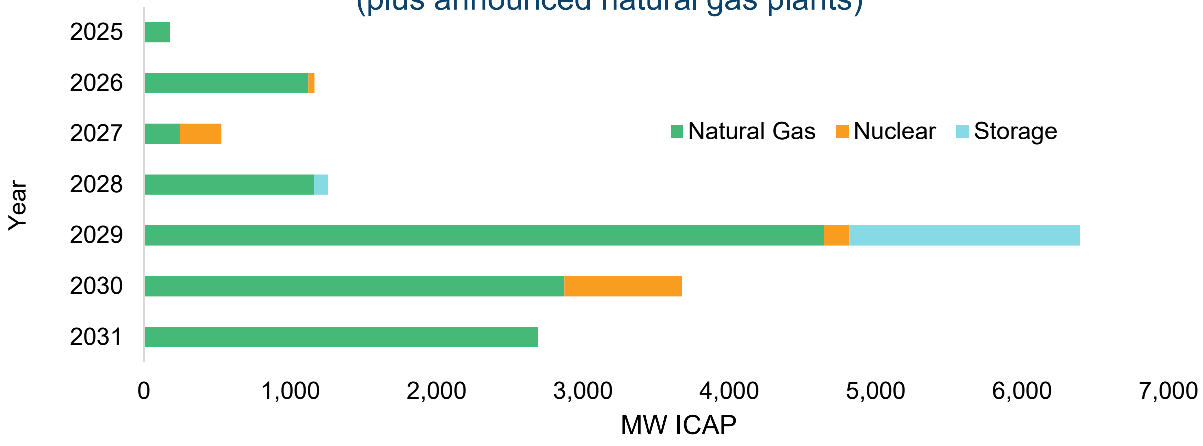
Generator interconnection – costs

A ~1.5GW gas unit in the ATSI zone withdrew from the interconnection queue due to high estimated costs.

Recent and expected new entry of capacity

- In 2025, only 2.1 GW of new generation came online. It was mostly solar, which carries lower accreditation ratings than thermal resources.
- PJM's Reliability Resource Initiative (RRI), which provides expedited interconnection for projects selected to meet resource adequacy needs, only identified <10 GW of new natural gas, nuclear, and storage capacity through 2031, and a large share was from uprates.
  - In addition, ~6 GW of new natural gas plants are projected to enter by ~2029.

Near-term Additions of High Accreditation Resources through RRI (plus announced natural gas plants)



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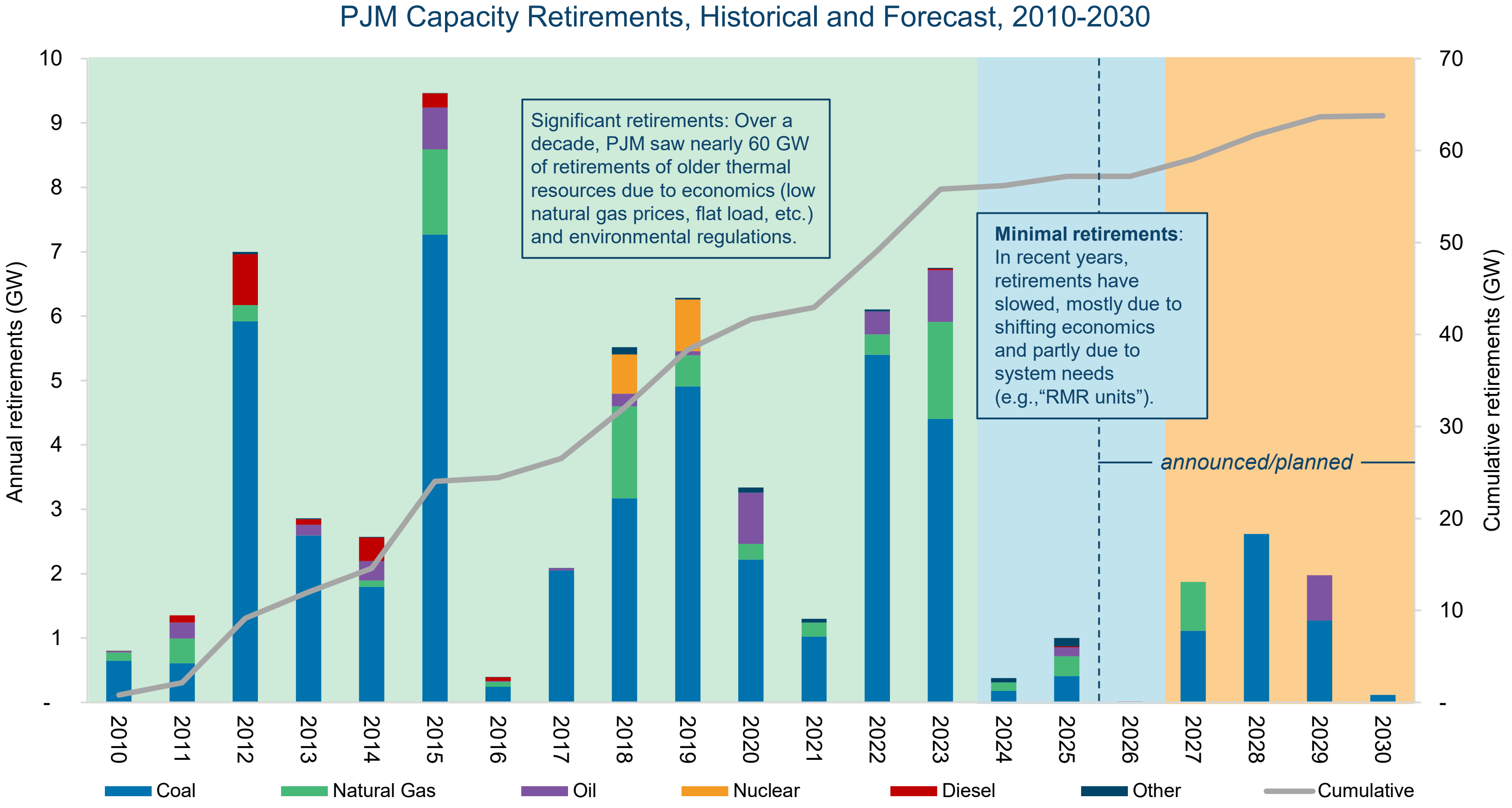
Retirements: Nearly 60 GW of thermal resources have retired in PJM since 2010, with future retirements uncertain due to possible policy/regulatory interventions



Source: PJM Generator Deactivation Data

Uncertain retirements: Looking forward, there are major planned retirements, but many are uncertain given pressures to remain online, including:

- Vastly improved economics (i.e., capacity prices)
- Shifting state policy in response to resource adequacy concerns
- Federal mandates, including DOE 202(c)

DOE use of 202(c) to delay retirements

The Dept. of Energy has increasingly used emergency authority under Section 202(c) of the Federal Power Act to delay retirements.

- Already used for the Eddystone unit in PJM
- Only lasts for 90 days, but DOE has extended multiple times and likely will continue to do so
- DOE likely to expand the use of 202(c) in PJM

Looking forward: Inevitable interventions to protect affordability

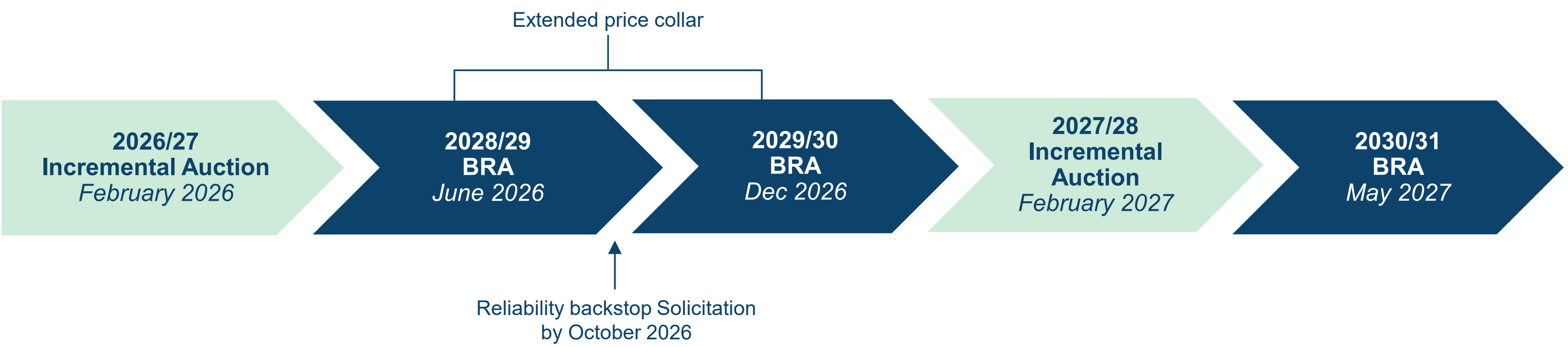
Upcoming capacity auctions

- The next BRAs will be in June 2026 (DY 2028/29) and December 2026 (DY 2029/30).
- PJM will extend the price collar for this auction, consistent with guidance from the White House and Governors (see next slide).
- **Given this likelihood, further interventions in future auctions are inevitable to address electricity affordability and reliability concerns.**

Interventions can take many forms. Each address capacity pricing and resource adequacy differently.

- **Price controls –** Caps on capacity prices, such as seen in the "collar" for the past 2 auctions. Not a solution to bring additional MW.
- **Large load mandates –** Requirements for new loads to receive interconnection and/or full grid services (such as capacity provision). One example is "Bring Your Own Generation" requirements.
- **State policy/regulation –** Subsidies for new capacity at scale, support for utility-provided solutions, contracts for new entrants, etc.
- **Separate pricing for new entry –** Moving away from single-clearing price auctions that pay the marginal capacity price to all resources.
- **Matching large loads with new capacity –** As outlined by the White House and PJM governors (see next slide).

BRA schedule, highlighting several near-term interventions



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Driven by affordability concerns, the White House and Governors directed PJM to hold a reliability backstop solicitation and extend the offer cap

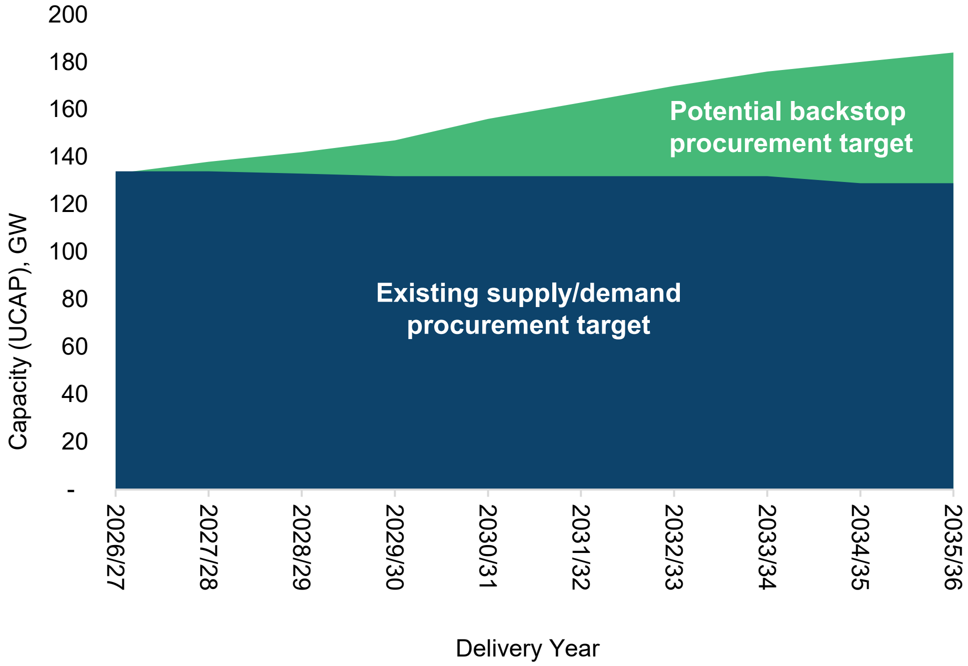
Outline of the White House and Governor Intervention

On January 16, 2026, the White House announced a **bipartisan Statement of Principles** signed by the governors of 13 states in PJM and the Secretaries of Energy and Interior. The goal is to build new generation for data centers while ensuring affordability for non-data center customers.

Further, the Statement directs PJM to:

- Hold a **reliability backstop solicitation** for new capacity to serve data centers. The solicitation must be held before October 2026 and have a 15-year tenor. Solicitation costs are to be first allocated to utilities with data centers, with any remaining costs allocated to utilities that are short capacity.
- **Extend the price cap**, which was set to expire, for an additional two auctions (the 2028/29 and 2029/30 BRAs) to protect retail customers.
- **Accelerate generator interconnection, improve large load forecasts, and reform the capacity market** to “ensure long-term viability” before the 2030/31 BRA, scheduled for May 2027, at which point “normal” BRAs return.

Potential target for PJM’s 2026 Reliability Backstop Solicitation
(as presented by PJM)



Reliability Backstop Solicitation and impact on PJM’s future capacity market

While there is significant potential for the backstop solicitation to contribute to a solution, it remains to be designed and it carries significant uncertainty for participation levels, impact on capacity prices, and other outcomes going forward.

The procurement-performance gap

Flexibility-centered large load policies overlook recent lessons

Authors

Dmitry Balashov
Principal

Margarita Patria
Principal

Our thanks to ***Charles Zhou for*** *research support.*

Indicators of change

Order 2222 revealed a gap between flexibility theory and planning and implementation practice – creating lessons that now resonate for data centers. These indicators track whether data center policies are bridging that gap or widening it.

- **Delayed RTO responses to new federal policies:** FERC expected Order 2222 compliance to take 270 days: it will now take some RTOs a decade. We are watching for signs of drag in RTO responses to recent large load-related FERC / DOE orders.
- **Share of data centers seeking BTM co-location:** The number of data center developers seeking connection behind-the-meter signals the degree of misalignment between the achievable grid connection speed and loads' expectations.
- **Interconnection queue revision frequency:** The number of times RTOs revise their load study procedures in a short period – indicating continued stakeholder dissatisfaction with connection processing (*See: MISO '24 / '25 & ERCOT late '25*).
- **Abrupt tweaks to recently released plans:** Changes to plans, policies, and programs after their official announcement– suggesting pace of evolving information and intensity of internal debates (*See: SPP's 2025 ITP transmission portfolio revision).*
- **State-level proactive actions:** As federal policymakers increasingly venture with comfort into the "gray area" of the federal / state energy policy mandate, watch for pre-emptive policies released by state Commissions to retain control of the issue.

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The promise of load flexibility: Haven't we seen this before?

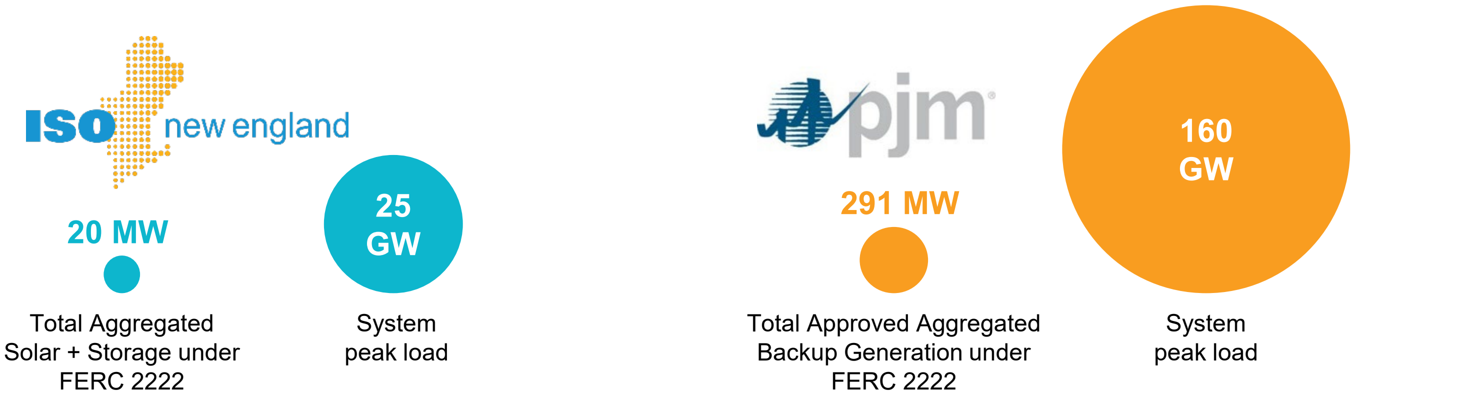
The recent context

Trump's January 16, 2026 direction seeks to address PJM's capacity shortage. The policy response reflects sophisticated thinking about cost allocation and investment certainty. By requiring data centers to shoulder responsibility for new generation buildout through long-term contracts, it addresses legitimate concerns about free-riding and cost-shifting to existing ratepayers. The policy response reflects sophisticated thinking about cost allocation and investment certainty, yet the policy debate has limited consideration of recent precedent.

Order 2222: The original flexibility shortcut

The industry has confronted this exact challenge recently. FERC Order 2222, issued in September 2020, promised to revolutionize wholesale markets by enabling distributed energy resources (DERs) to participate alongside traditional generation. RTOs filed compliant tariffs, investors funded DER aggregation platforms, and the paradigm shift appeared inevitable.

FERC Order 2222: Limited results after five years



Since inception, FERC Order 2222 resources (solar + storage) account for **0.08% of total system peak load.**

Since inception, FERC Order 2222 resources (solar + storage) account for **less than 0.2% of total system peak load.**

Lessons for data center planning

This is not about regulatory failure or utility obstruction. Every RTO made significant efforts to comply in time and many barriers came down. What did not materialize at expected scale was participation because the order did not fully resolve the fundamental tension between operational flexibility and planning certainty that continues to be the price of entry for dispatch.

That same tension now governs the data center debate. The scale has changed from kilowatts to hundreds of megawatts, but the underlying question is identical: can planning systems built for reliability accept operational flexibility as a substitute for firm capacity? Order 2222's limited participation and extended timelines indicate challenges in this approach, providing a direct roadmap for current large load policy discussions.

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Our survey reinforces that a variety of different flexible and distributed solutions are being explored, but may still be in the early innings

DERs are increasingly viewed as a potential resilience asset. How would you characterize the industry's current ability to integrate DERs effectively as part of the resilience toolkit?

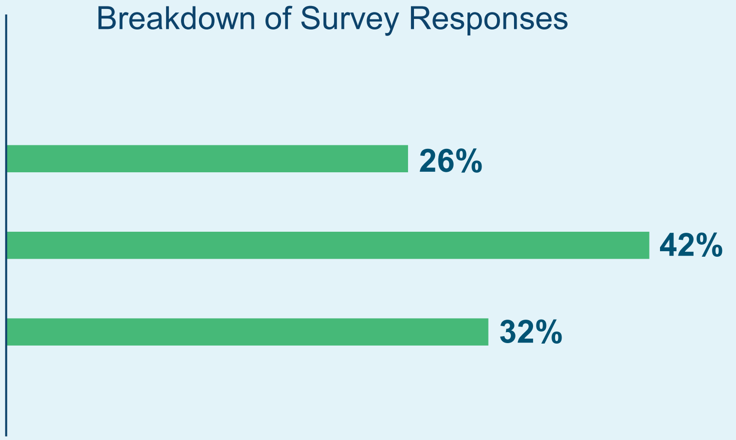
None / counterproductive – Current frameworks may actually hinder DER participation during resilience.

Minimal – DER integration remains fragmented and largely outside formal resilience planning.

Early stage – The industry is still experimenting; DERs are not yet systematically incorporated into resilience strategies.

Progressing – Pilot programs and selective deployments show promise, but scalability and coordination remain limited.

Leading edge – DERs are being actively integrated into resilience and reliability planning, supported by strong regulatory and operational frameworks.



Utilities are exploring a range of distributed and flexible resource strategies to enhance reliability, resilience, and system efficiency. Which of the following approaches is your organization actively pursuing?

Select all that apply

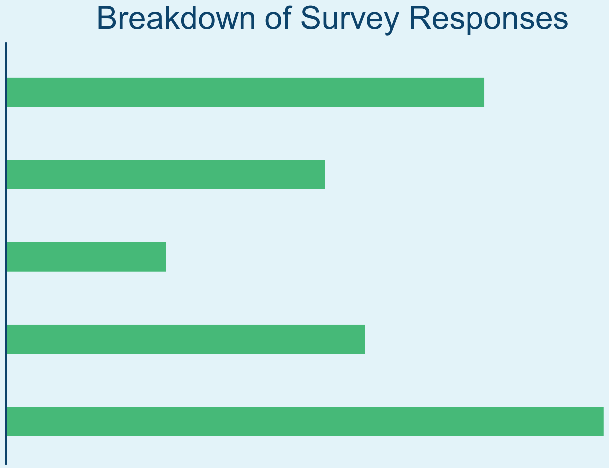
Grid-enhancing technologies and advanced conductors – Expanding transfer capability and system visibility without major rebuilds.

Virtual power plants (VPPs) – Aggregating distributed assets to provide grid services at scale.

Community microgrids – Developing localized resilience and flexibility solutions serving critical loads or communities.

Behind-the-meter resources (including storage) – Integrating customer-sited generation, storage, and control systems.

Demand response and flexible load programs – Leveraging customer or industrial flexibility to manage peak demand and grid stress.



The promise that wasn't: A FERC order sprint turned to a saga

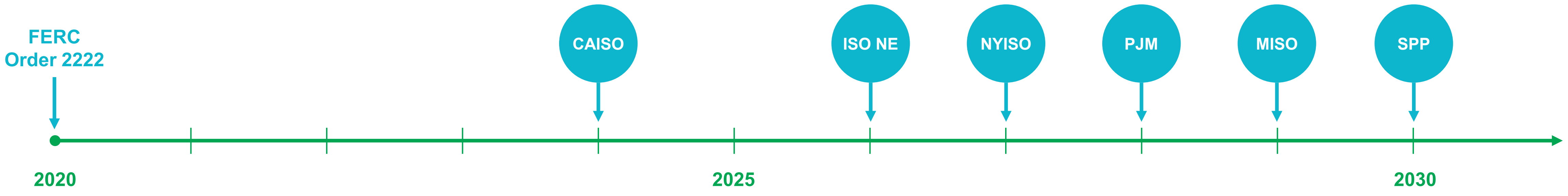
When FERC issued Order 2222 on September 17, 2020, it directed RTOs and ISOs to revise their tariffs to allow aggregated DERs like batteries, rooftop solar, and smart thermostats to participate directly in wholesale capacity, energy, and ancillary services markets. The order removed formal barriers that had prevented small, customer-sited resources from competing alongside traditional generation. All that was left to do, it seemed, was for ISOs and RTOs to implement it.

FERC set a 270-day compliance deadline. Industry press called the order a "game changer." Investor presentations projected DER aggregators as nimble technology platforms poised to leap over the complexity and conservatism of traditional utility planning. Share prices for publicly traded aggregators like Sunrun and Generac peaked around this period – though admittedly they were also buoyed by complementary tailwinds of low interest rates and generous Inflation Reduction Act subsidy announcements. Competitively priced "flexibility at scale" seemed like an inevitability.

The implementation timeline tells a different story. As of January 2026, only two of the six RTOs are within the striking distance of implementation: California ISO completed its implementation as of November of 2024, and ISO New England appears on track for late 2026. New York ISO expects full implementation by end of 2026. PJM will not achieve energy market participation until February 2028, with capacity market access delayed until the 2028/2029 delivery year. MISO is working toward two-phase implementation ending in June 2029. SPP's proposed implementation date is second quarter of 2030 – nearly a full decade after the order was issued.

FERC Order 2222 Latest Implementation Timeline by RTOs

Latest full compliance timeline estimates



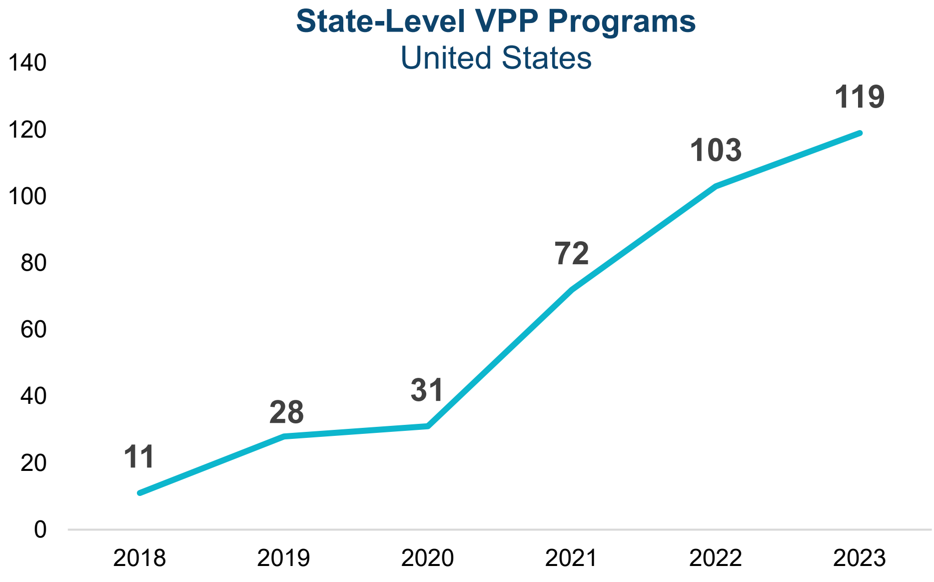
DERs & VPPs footprint grew, but not where FERC hoped it would

The wholesale market participation of aggregated DERs that has materialized is modest – to the point of invisibility against system scale. PJM approved approximately 290 MW of aggregated backup generation in its 2023 capacity auction – a figure that is vanishingly small against PJM's system peak of over 160 GW. Critically, this capacity represents a resource type that market operators already understand: dispatchable backup generation with firm fuel supply and discrete operating obligations. It fits much more naturally into the existing resource accreditation frameworks in ways that probabilistic flexibility does not.

Meanwhile, at the state level, DER programs have proliferated to a greater degree. Since 2019 the number of VPP and DER aggregation programs grew from fewer than a dozen pilots across FERC-regulated markets to more than 100 active programs. Many remain quite small, but the activity level has been far more vibrant. While some publications report higher numbers of VPP instances, the difference appears to relate to counting methodologies (e.g. counting one program offered by two aggregators as two VPPs).

The VPP growth masks a critical detail: the vast majority operate under state regulatory jurisdiction, not wholesale market integration. In PJM, for example, commercial and industrial demand response aggregators have long been active, with thousands of sites providing approximately 7 GW in PJM's capacity market, but these are legacy programs that predate Order 2222, operating under established measurement and verification protocols.

Even large increases in energy storage participation—such as ISO New England's procurement of over 1,800 MW in FCA 18—were driven by state clean energy mandates, utility solicitations, and Order 841 reforms, not Order 2222 aggregation.



Source: vppdata.com

Inspired by state actions & outdone by them

FERC Order 2222 was modelled after California's Distributed Energy Resource Provider (DERP) model that allowed participation of aggregated DERs in the one-state wholesale market as early as 2017. Since the FERC order's release, the bulk of the VPP program growth occurred under the auspices of state regulator-authorized programs that primarily target more local grid benefits.

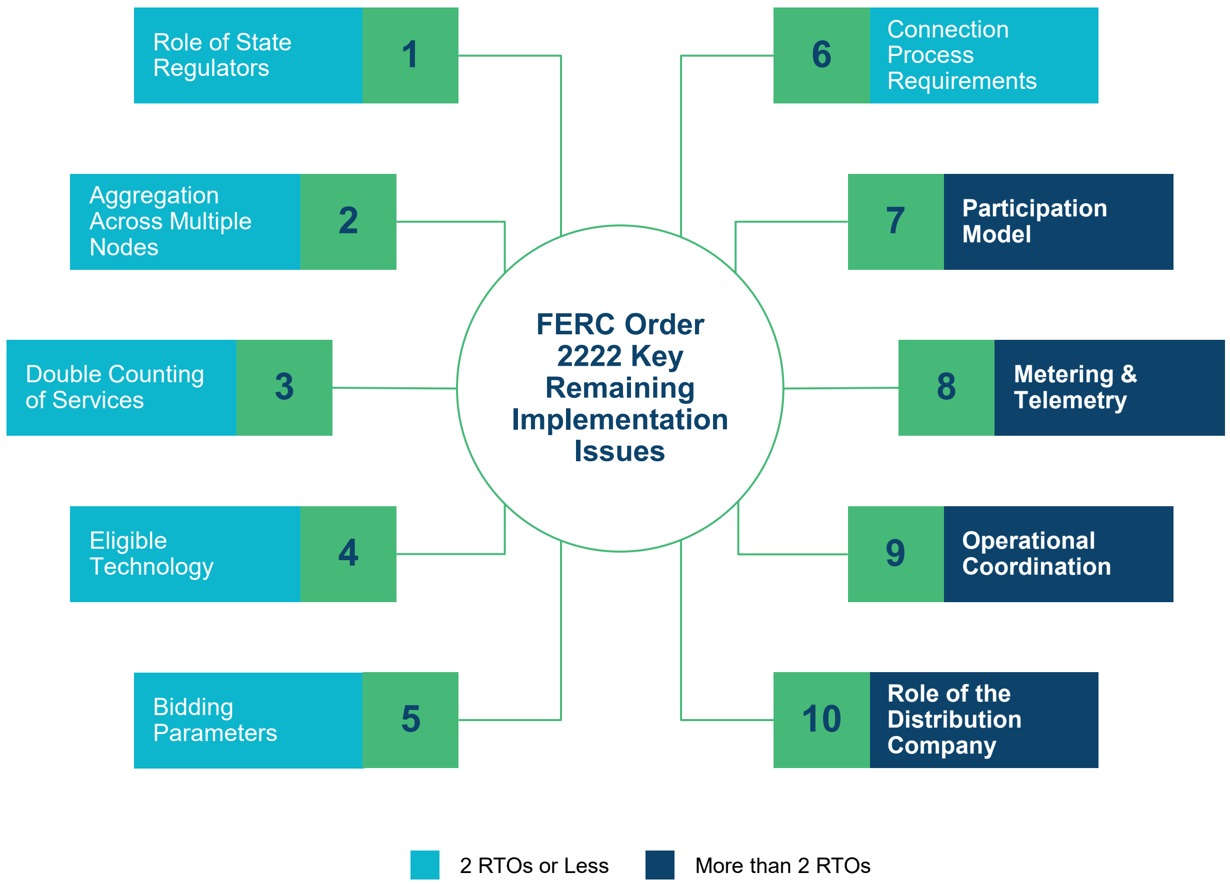
Wholesale market participation of DERs remains limited

The pattern holds across markets:

CAISO currently lists fewer than ten registered DER aggregators with market-based rate authority, despite being frequently cited as the "success case" for Order 2222 implementation – and the inspiration for the original order given California's earlier start in the DER aggregation space. **NYISO** shows only a handful of DER providers eligible for wholesale transactions, despite representing the jurisdiction with a robust state-level DER program landscape.

In **MISO** and **SPP**, no comparable volumes of new DER aggregation have materialized despite extensive compliance work on the parts of the market administrators.

Even **ISO New England**'s frequently cited 20 MW of aggregated residential solar-plus-storage that cleared in 2019 – the first time such resources participated in any capacity market relied on solar installations that state policies had enabled to exist over the preceding decade, according to the winning bidder Sunrun. While groundbreaking, this success came from a single aggregator with strong utility partnerships, deploying resources at pilot scale with measurement and verification requirements far easier to establish and maintain than mass market adoption would require.



So, what went wrong? Nothing, if you believe the market administrators acted rationally.

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Why compliance is not the same as participation

The central lesson from FERC Order 2222 is straightforward but critical: Regulatory compliance does not guarantee market participation at scale. Every RTO ultimately filed tariffs, often after multiple iterations and extended negotiations with FERC. ISO New England alone submitted eight compliance filings before receiving conditional approval, with implementation still ongoing. PJM filed its initial compliance plan in early 2022, received a deficiency letter in 2023, and did not finalize revisions until later that year. MISO's proposed implementation timeline was rejected as too slow, then reapproved with a schedule extending into 2029. While formal barriers were removed, actual entry into wholesale markets remained limited because the order did not resolve the planning and operational constraints that determine whether a resource can be relied upon for system reliability.

Planning requirements create practical barriers

To count as capacity, planners must assume a resource will perform under stress conditions, verify that performance, and defend those assumptions to regulators and ratepayers. Order 2222 enabled aggregation, but it preserved three fundamental realities. First, distribution utilities retain physical and jurisdictional control over customer-sited resources and may override wholesale dispatch for safety or reliability reasons. This is not obstruction; it reflects legal authority and operational necessity. Second, verification standards favor hard telemetry over probabilistic inference. Statistical baselines and portfolio diversity appear attractive in theory but tend to fail when customer behavior changes during extreme system conditions—the very moments when capacity is most valuable. As a result, ISOs imposed telemetry, metering, and coordination requirements that limited eligible participation to resources with proven infrastructure. Third, cost recovery for enabling infrastructure—such as DERMS, advanced metering, protection upgrades, and feeder enhancements—remained uncertain. Absent regulatory clarity on who pays and how, utilities rationally slowed investment.

Market operators adapted to prioritize reliability

Faced with these constraints, ISOs modified their tariffs to reduce operational risk. They preserved or expanded utility veto points, required granular telemetry, restricted aggregation to specific nodes, or imposed minimum size thresholds that effectively excluded residential resources. Each change improved planning defensibility but reduced participation. This outcome is not paradoxical; it is the predictable result of asking institutions designed around centralized generation to internalize resources whose availability and control sit partly outside their authority. Comfort levels ultimately reflected the degree of control and accountability planners were willing to assume.

Order 2222 lessons for large-load planning

What the experience revealed

Market reforms relying on operational flexibility succeed only when institutions can translate flexibility into defensible planning assumptions. Where translation fails, progress stalls. Order 2222 under-delivered not because aggregation was flawed, but because it exposed how much infrastructure is required before flexibility can be relied upon for reliability.

The experience revealed conditions under which flexibility becomes operational: hard telemetry, enforceable obligations, jurisdictional clarity, and cost certainty. These require years of system upgrades and regulatory coordination. Order 2222's 270-day compliance clock became five-to-ten-year timelines because planning institutions cannot assume performance without proof.

Large-load interconnection faces the same constraint with higher stakes. Speed will not come from voluntary curtailment commitments or self-sufficiency claims. It will come from mechanisms planners can model and regulators can defend.

Requirements for progress

First, service definitions must be precise enough to be modeled. Vague "flexibility" commitments are unusable in reliability planning. Only binding, verifiable service levels—maximum grid draw under contingencies, guaranteed curtailment response times, financial penalties for non-performance—can be incorporated into planning models. SPP's High Impact Large Load programs illustrate this by defining exposure rather than assuming flexibility. FERC's December 2025 directive for PJM to develop transmission service types reflects the same logic, but defining those services will require extended stakeholder processes.

Second, cost allocation must align with state regulatory authority. Transmission and enablement infrastructure require state commission approval for cost recovery. Federal acceleration that bypasses this produces delay and litigation, not infrastructure. The thirteen governors' endorsement signals meaningful political support for assigning costs to data centers. Translating that support into approved rate structures, however, requires commission proceedings in multiple jurisdictions on timelines measured in years.

Third, planners must assume flexibility fails under stress unless proven otherwise. Reliability standards are built around worst-case outcomes, not average behavior. The one-in-ten-year planning criterion cannot be satisfied by probabilistic resources unless they demonstrate performance under stress conditions. Order 2222 aggregators encountered this through repeated FERC deficiency letters demanding tighter definitions and stronger verification. Large-load developers will likely face the same requirements. This is not resistance to innovation; it is the price of making innovation durable where failure carries catastrophic consequences.

Now what?

The January 16, 2026 announcement from the Trump administration and PJM state governors represents a serious attempt to address real shortcomings in capacity procurement and cost allocation. It correctly rejects the notion that data centers can free-ride on existing capacity and recognizes that long-term contracts may provide investment certainty that annual auctions do not.

Implementation reality

What it does not change is the pace of implementation. Procurement mechanisms can be accelerated, but auctions can be held on compressed timelines only if auctions are not implementation. Implementation requires:

- Transmission upgrades requiring state approval and billions in investment
- Interconnection queues with tens of gigawatts in signed agreements awaiting commercial operation
- Coordination among transmission operators, distribution utilities, generators, regulators, and commissions operating under different authorities

The flexibility fallacy

The flexibility fallacy is appealing because it sounds modern and efficient. But flexibility that cannot be verified, enforced, or translated into conservative planning assumptions is not a resource – it is a risk. Planning institutions move at the speed of verification, not aspiration. That speed is slow, but it is how reliability is preserved.

Historical context

Order 2222 took 270 days on paper and many years in practice. The gap between procurement and performance for large-load policy will be similar, and likely wider given the scale and complexity involved.

"To what extent do you believe utilities will need to fundamentally transform their business models to respond effectively to data center growth?"

Over 50% of survey respondents agree that significant adaptation is needed, including a rethink on infrastructure planning, regulatory engagement, and service offerings, while the remainder is evenly split between moderate adjustments or major transformational (evolve toward a more commercial, customer-centric model).

Regulatory evolution and affordability pressures

NERC’s evolution: Strategic risk management over compliance

Authors

Kirsten Maw
Associate Principal

Matthew Moore
Principal

Indicators of change

These indicators help us track how NERC’s shift from compliance to strategic risk management is raising resilience standards, changing compliance frameworks, and reshaping regulatory priorities.

- **Regulatory framework changes:** Revisions to NERC's risk elements and CMEP priorities, updates to reliability standards, and modifications to enforcement procedures.
- **Risk categorization evolution:** Increasing emergence of new strategic risk categories such as extreme weather, inverter-based resources, supply chain vulnerabilities, and cyber threats.
- **Guidance and communications:** Growth in guidance and alerts tied to modernization themes including resilience, readiness, cybersecurity, and grid transformation priorities.
- **Enforcement outcomes:** Rising non-compliance findings linked to readiness gaps, shifts in penalty structures, and changes in settlement patterns for strategic vs. traditional violations.

NERC's strategic shift reshapes compliance approach

NERC has shifted from a compliance-driven model to a strategic, risk-based approach that prioritizes resilience, modernization, and emerging risks while maintaining compliance as a cornerstone for reliability and readiness.

The transformation

Rather than focusing solely on strict compliance, NERC now integrates strategic risk considerations into its framework. Between 2021 and 2023, emerging risks such as supply chain vulnerabilities, extreme weather events, and inverter-based resources (IBRs) were incorporated, signaling a broader shift toward anticipating and managing system-wide threats.

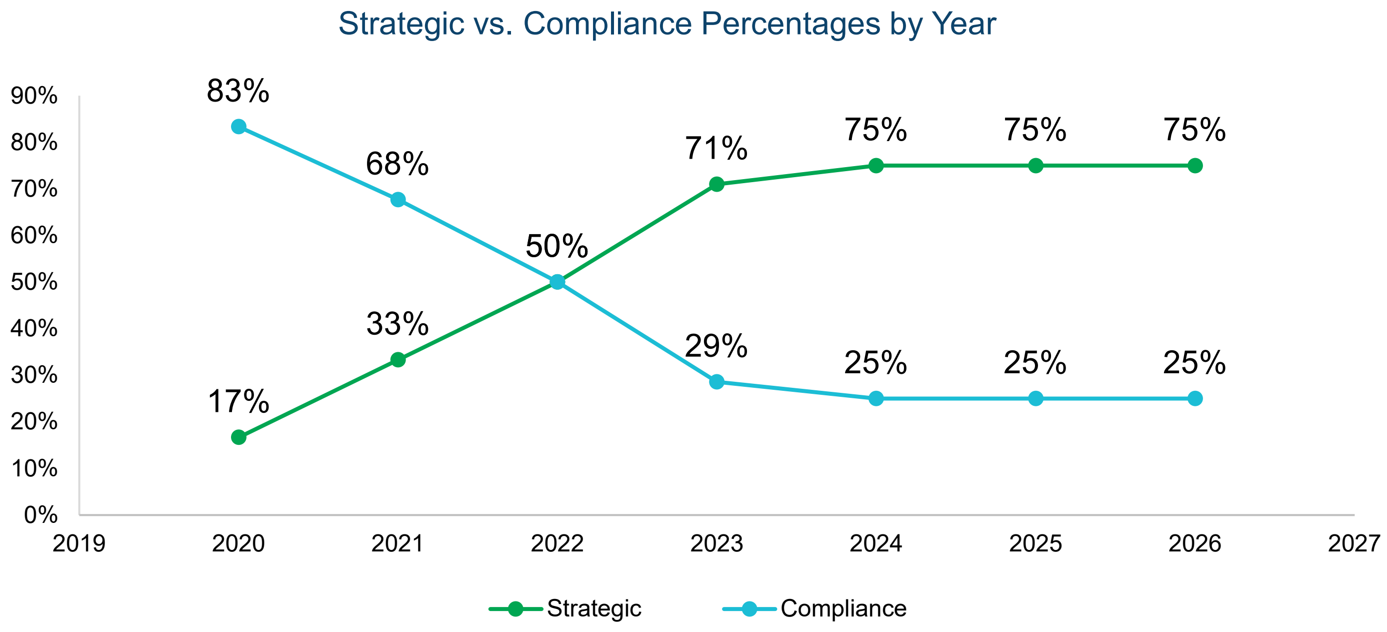
Evolved enforcement approach

While most issues are still resolved without financial penalties, the value of assessed penalties is increasing. NERC continues to reinforce that reliability and infrastructure readiness are essential, with leading organizations now positioning compliance teams as strategic assets in high-priority areas such as Facility Ratings, Inverter-Based Resources, and Protection System Maintenance.

Strategic advantage

Organizations that embrace integrated risk management, proactive assessments, and cross-functional collaboration can anticipate emerging threats more effectively and respond with greater agility.

Tracking NERC's strategic evolution



Strategic vs. compliance focus shift

- 2022 marked a turning point: NERC and regional entities began prioritizing reliability goals over compliance goals.
- Strategic risk elements increased from 17% in 2020 to 75% in 2024, while compliance risk elements declined from 83% in 2020 to 25% from 2024 onward.
- Strategic risk focus plateaus at 75% from 2024 onward, indicating stable strategic emphasis.
- The focus has shifted from simply maintaining a compliance culture to actively prioritizing reliability and implementing best practices.

Compliance risk	Strategic risk
Linked to mandatory standards, regulatory requirements, and strict operational compliance. Noncompliance typically leads to violations or penalties.	Focuses on long-term resilience, strategic system planning, and addressing emerging threats. Extends beyond basic compliance to emphasize broader, future-oriented grid reliability.

Source: Compliance Monitoring and Enforcement Program. *CMEP IP 2019-2026.* CMEP Resources.

Patterns driving the evolution

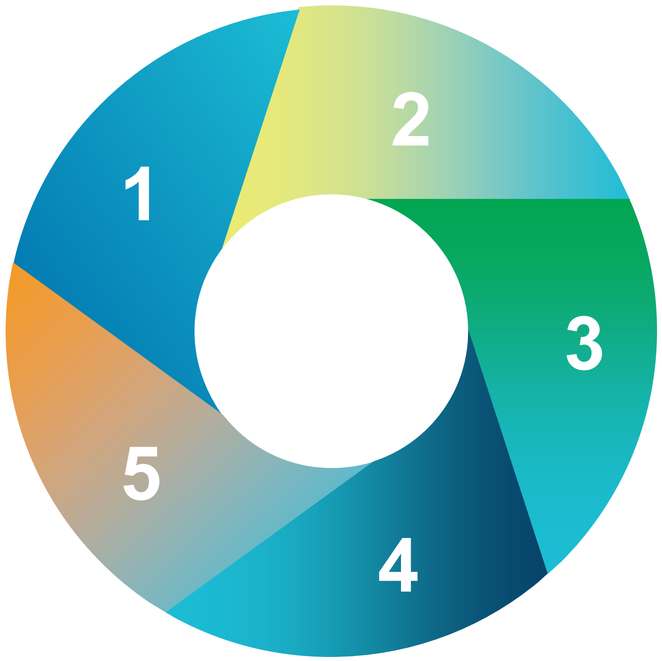
NERC's strategic transformation responds to five evolving risk patterns that traditional compliance couldn't address.

Stable, long-term issues

Remote connectivity, supply chain and critical infrastructure interdependencies appear consistently from 2019 through 2026. These represent ongoing challenges that are not diminishing over time.

Consolidated risk trends

Specific risks (cold weather, stability studies, IBRs) are gradually consolidated into broader categories like extreme weather and grid transformation.



Persistent strategic themes

Grid transformation remains a dominant priority from 2019 onward and surfaces on CMEP IP in November 2025, signalling a long-term modernization focus. Security risks evolve from broad concerns to specific physical security emphasis by 2024-2026.

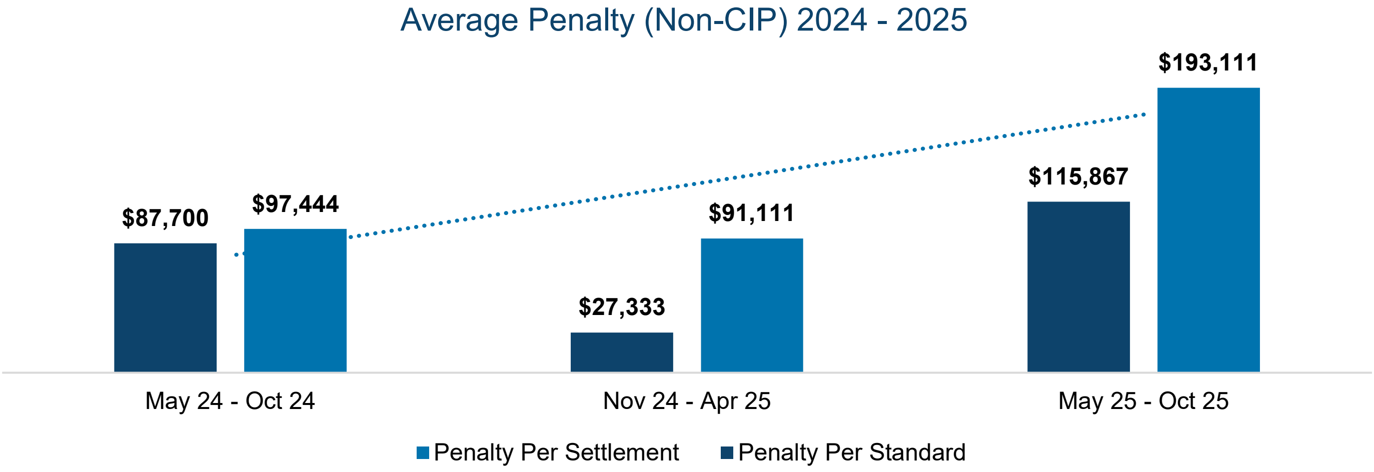
Strategic evolution of priorities

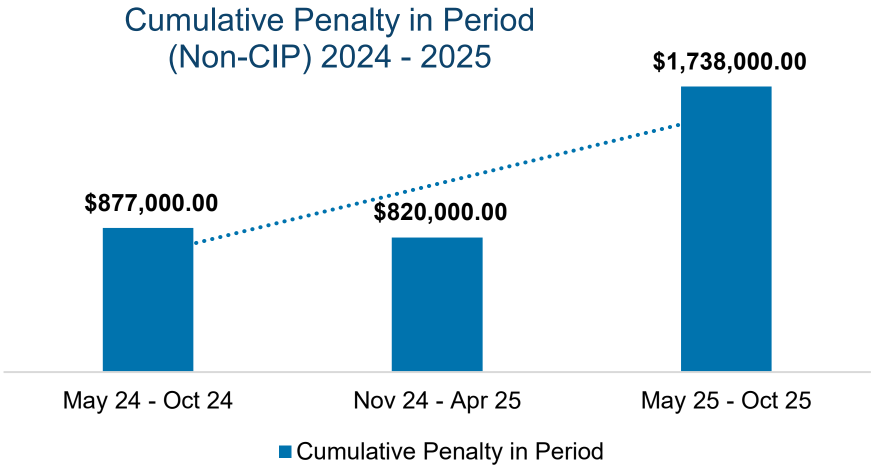
Technical priorities progress from foundational compliance/reliability (protection system coordination) to advanced grid elements (IBRs, transmission planning, facility ratings).

Weather risks intensify

Shift from isolated ***Extreme Events*** (2019–2021) to ***Resilience to Extreme Events*** (2023 onward) and ***Extreme Weather Response*** (2024–2026), suggesting a broader approach to weather-related risks.

NERC penalties for non-CIP reliability standards are trending upward both per violation and cumulatively, reflecting increased enforcement and a growing emphasis on integrating reliability objectives across organizations.





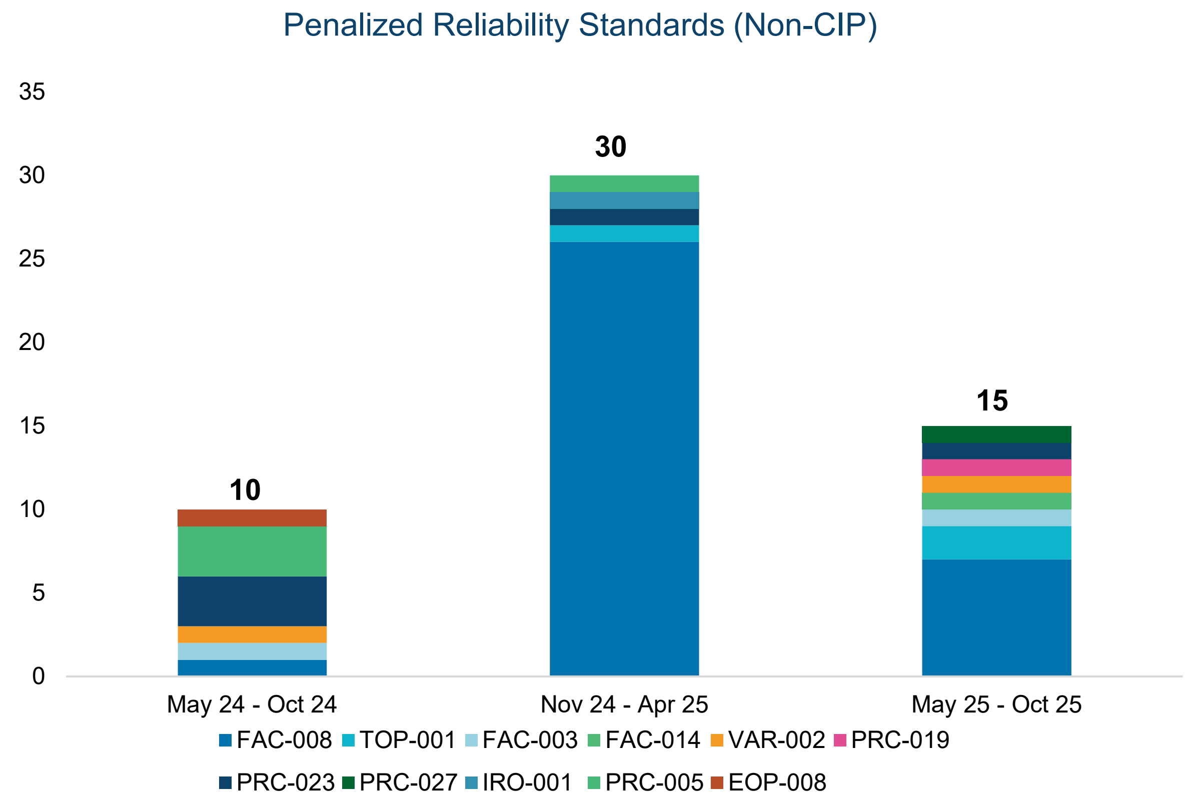
In a review of violations related to the Operations and Planning Standards, penalties are increasing per violation and per settlement.

While NERC and the regions continue to focus on risks to reliability, penalties submitted to FERC are increasing in the aggregate and on a per violation basis, making reliability and compliance with key reliability standards more important.

The incentive continues to be on integrating reliability objectives throughout an enterprise and leveraging compliance teams as strategic partners to an organization.

Source: NERC Filings to FERC. *Enforcement Dispositions*

Violations tied to Facility Ratings (FAC-008) dominate penalty trends, with occasional spikes in inverter and protection system maintenance standards, underscoring a persistent focus on accurate ratings and asset validation.



Source: NERC Filings to FERC. *Enforcement Dispositions*

FAC-008 remains the most penalized Standard, keeping a NERC and regional entity focus on accurate Facility Ratings. Asset Management and equipment inventory validation remains important to assuring adherence to Facility Ratings Methodology.

Violations related to Inverters and Protection System Maintenance also remain frequently penalized.

Integrate reliability & strategic goals: Enable better system modeling, which informs investment.

Cross-functional coordination: Compliance requires collaboration between engineering, operations, and compliance teams—making it a strategic initiative rather than a siloed task.

High impact standard: FAC-008 violations often result in significant fines because they can directly affect bulk electric system reliability.

Regulatory evolution and affordability pressures

The affordability risk for utilities

Author

Matt DeCourcey
Vice President

Indicators of change

Key indicators suggest that focus on affordability has intensified:

- **Regulatory signals:** New affordability-focused dockets, shifts in commission language, expanded prudence reviews, and changes in approval timelines.
- **Legislative activity:** Bills or executive actions targeting ratemaking, capital recovery, earnings limits, or utility spending.
- **Rate case outcomes:** Disallowances, deferrals, changes to riders or trackers, and evolving expectations for spending discipline.

Affordability debate focuses on national price averages

Recent studies report that, on average, American utility rates are up sharply in the past few years. Polling indicates that most customers are concerned about their bills and feel "powerless" in the face of rate increases. Commentary abounds that an affordability crisis is upon us, or soon will be, and that dire consequences could soon follow.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NEWS

Surging electricity costs are pushing residents to desperate measures. Here's how some West Virginians are struggling through.

As power costs continue to rapidly increase, West Virginians are forgoing basic necessities to make ends meet.

by Sarah Elbeshbishi January 4th, 2026


THE WALL STREET JOURNAL.

Be Prepared to Keep Paying More for Electricity

Data centers are getting much of the blame lately for rising power costs, but they aren't the only catalyst

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By Jennifer Hiller Follow and Max Rust Follow

Dec. 29, 2025 5:30 am ET


Maryland agency warns BGE customers about 2026 rate increases as rising energy bills prompt concerns

By JT Moodee Lockman

Updated on: January 6, 2026 / 8:14 PM EST / CBS Baltimore

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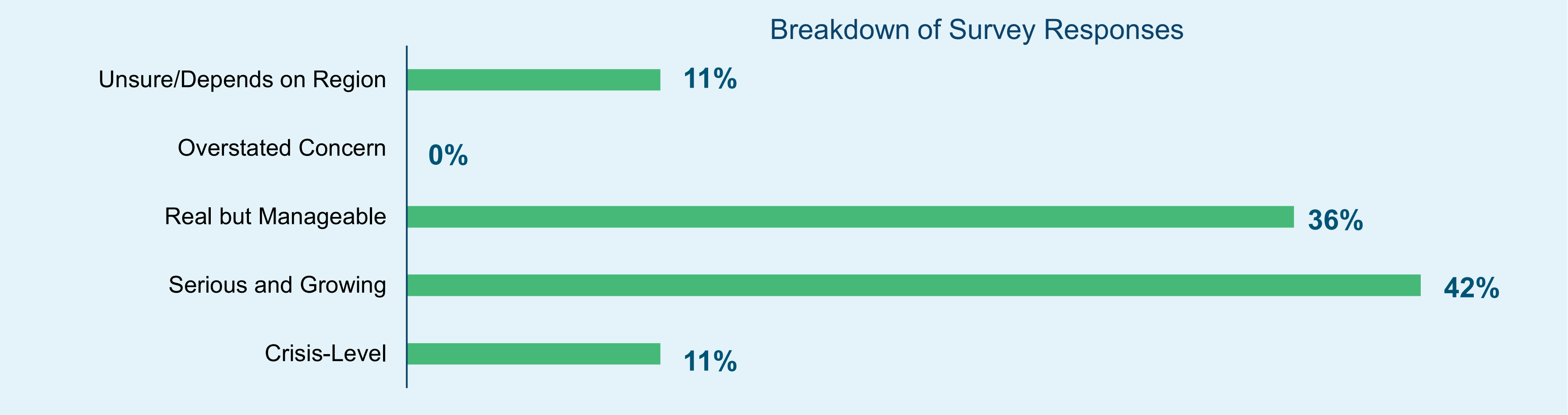
Affordability has become a dominant theme in utility and regulatory discussions, often cited alongside reliability as a top public concern. In your view, how would you characterize the current narrative around affordability in the power sector?



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Rate trends more nuanced than narratives suggest

In a recent report prepared for the Edison Electric Institute (EEI), we analyzed the recent trends in retail electric rates.

Key findings from the study:

- Prevailing narratives that there is a broad national trend of rapidly rising electricity rates are inaccurate or incomplete. Trends that use national averages can be misleading because those data obscure important differences among the different rates that comprise the average.
- Trends in the nationwide average are heavily influenced by large rate increases in specific areas, including in the Northeast and California, and in those jurisdictions, data centers were not the cause of such rate increases.
- Going forward, utilities and their state regulators have committed to protecting retail customers from rate increases caused by new data centers. The protections being embedded in new tariffs and ratemaking measures are designed to prevent subsidies from existing ratepayers, help maintain utilities' creditworthiness, and may put downward pressure on existing customers' retail rates.


CRA Charles River Associates

Retail rate trends in the US

February 2, 2026

Authors

Matthew DeCourcey
Mayank Saraswat

Charles River Associates
200 Clarendon Street
Boston, Massachusetts 02116

Prepared for

Edison Electric Institute
701 Pennsylvania Avenue NW
Washington, DC 20004

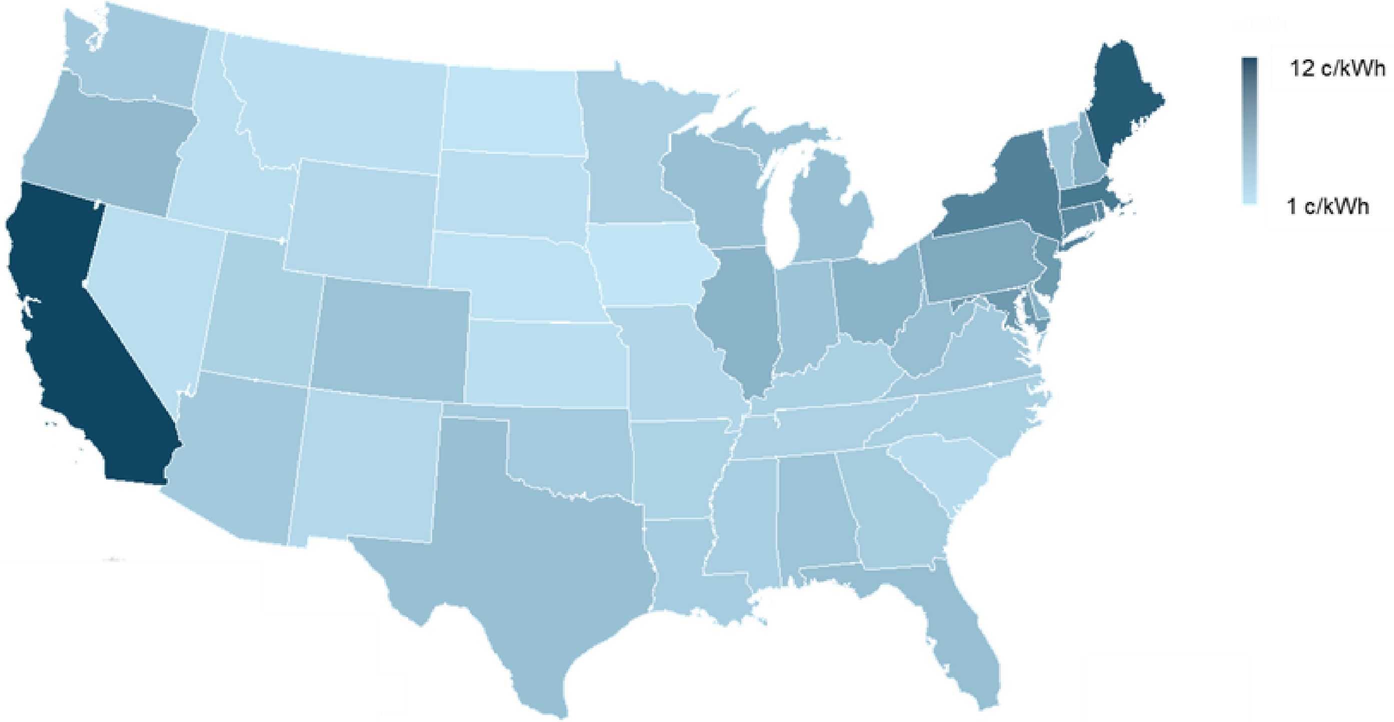
Read the full report here

Local conditions drive affordability trends

The report found that trends in the nationwide average were heavily influenced by large rate increases in specific areas, as seen in the visual. Most other places experienced fairly stable rates, where rates increased either more slowly than inflation or at about the same rate.

Level of concern	Region
High	**California**, where spending on wildfires has been a primary driver of a large increase in retail electric rates in recent years
Mid/high	The **Northeast US**, particularly New York and New England, where increases in wholesale electric costs passed through in states where utilities do not own generation have increased rates considerably

5-year Change in Electric Rates



Charles River Associates

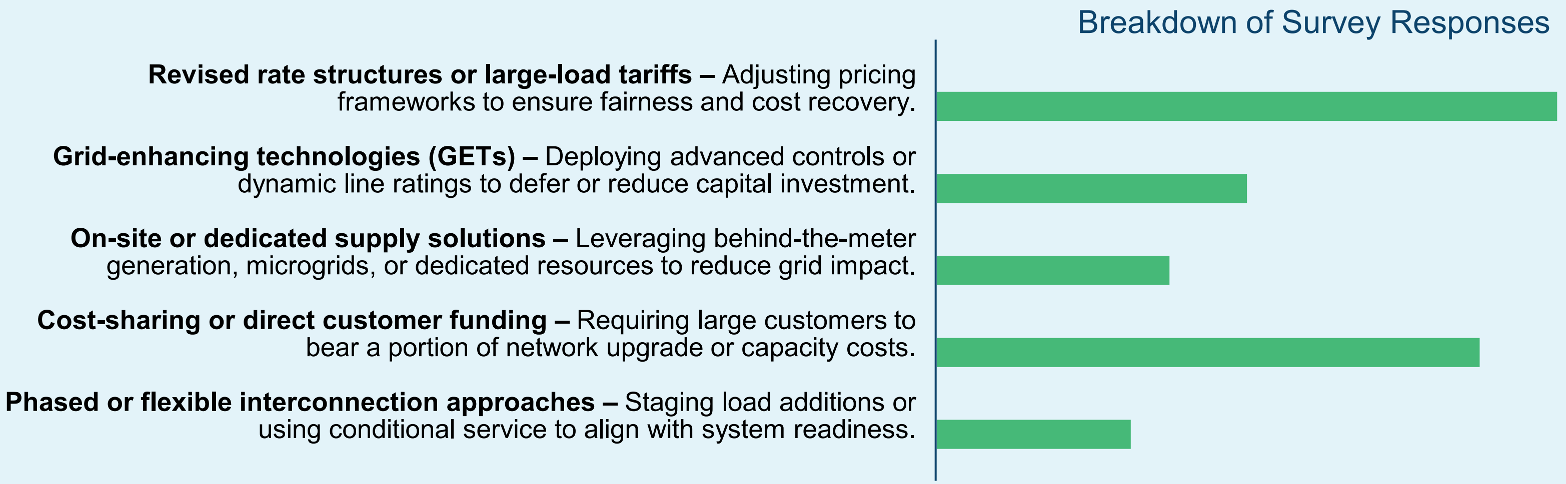
New data center tariffs insulate customers from service costs

In both the Northeast and California, rate increases were not caused by data centers. Regardless, there have been observable actions taken by utilities to implement new tariffs and agreement to protect existing customers across the US. Fundamental to these tariffs and agreements is the requirement that new large loads fully or substantially fund the new generation, transmission, and other upgrades needed to serve them. The large loads are also required to pay for the studies to determine any upgrades. The tariffs and agreements generally ensure that utilities can recover their costs, including a rate of return, from the infrastructure they own and operate to serve new large loads. These retail provisions protect customers from paying the costs of building energy infrastructure to serve new large loads, ensuring that the incremental costs to serve large loads are borne by the large loads themselves, which prevents cost shifts to a utility's existing customers.

Our survey also found that the most effective way to protect ratepayers would be with revised rate structures/large-load tariffs or other cost-sharing mechanisms.

Data center growth is accelerating across multiple regions, creating both opportunity and pressure on system planning and customer costs. Which strategies are prioritized by your organization to manage large-load growth while protecting existing ratepayers?

Select all that apply



Effective utility managers are finding opportunities to actively navigate a landscape in which affordability is increasingly prioritized. The most successful generally share a handful of best practices.

Recognize risk

IOUs are not in a business-as-usual environment. Diagnosing the situation and pivoting to effective strategy is critical.

Understand local dynamics

All relevant dynamics are local. Each IOU should understand what its rates have done, why its costs have changes, and how each of those trends vary from reported metrics.

Communicate and educate

Engage early and often with regulators, policymakers, and stakeholders. Help them understand the local situation and what the IOU is doing to serve customers and control costs.

Be proactive

Bringing the conversation to constituents creates a tremendous advantage. Be prepared to invest, operate, and manage the business different.

Observable utility best practices

Affordability risk is increasingly treated as a standing factor in regulatory proceedings, and the outlook often shows up not only in testimony but also in planning assumptions and internal decision screens.

Utilities frequently build a local affordability fact base (rates, cost drivers, bill impacts, and customer segmentation) to distinguish what is truly local from broader narratives that dominate public discourse.

Stakeholder engagement is often structured around education rather than advocacy—walkthroughs of bills, tradeoffs, and scenarios are used to align on the local context before positions harden.

Affordability risk is increasingly treated as a standing factor in regulatory proceedings, and the outlook often shows up not only in testimony but also in planning assumptions and internal decision screens.

From capacity expansion to constraint management

Natural gas: An impending pressure point

Authors

Pat Augustine
Vice President

Charles Merrick
Senior Associate

Indicators of change

These indicators help us track how natural gas limitations are becoming the system's key constraint.

- **Henry Hub forward curve:** Whether future supply needs are being priced.
- **Volatility and regional basis spreads:** Early signs of system stress.
- **Rig counts and drilling activity:** Whether supply is responding.
- **Pipeline, storage, and generation FIDs:** Whether capital is stepping in.
- **Utility IRPs and regulatory rulings:** How trade-offs between short-term cost minimization and long-term system reliability are being resolved.

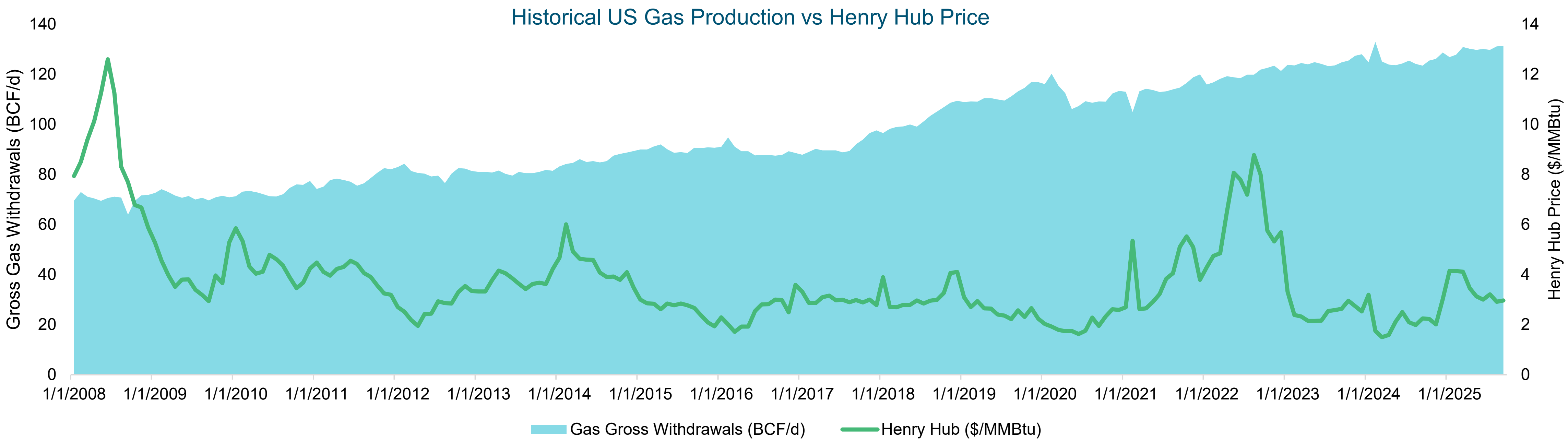
Shale fracking has driven sustained production growth

Development of shale plays has led to significantly increased natural gas production, while maintaining relatively stable pricing compared to the pre-2009 period.

Low price environment continues: Aside from the post-pandemic price spike of 2021-2022, natural gas prices have generally been at or below $4/MMBtu for the past decade. However, sustained low prices may discourage new drilling and encourage a low-price environment.

Industry activity has contracted: Rig count has not recovered from the COVID-19 pandemic and resulting industry consolidation, with producing wells declining from over 900,000 pre-pandemic to over 750,000 in 2022 and over 520,000 in 2024.

The ability to close and open wells will be a critical driver in determining how quickly supply can increase to match demand.



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Natural gas demand is expected to surge by 2034

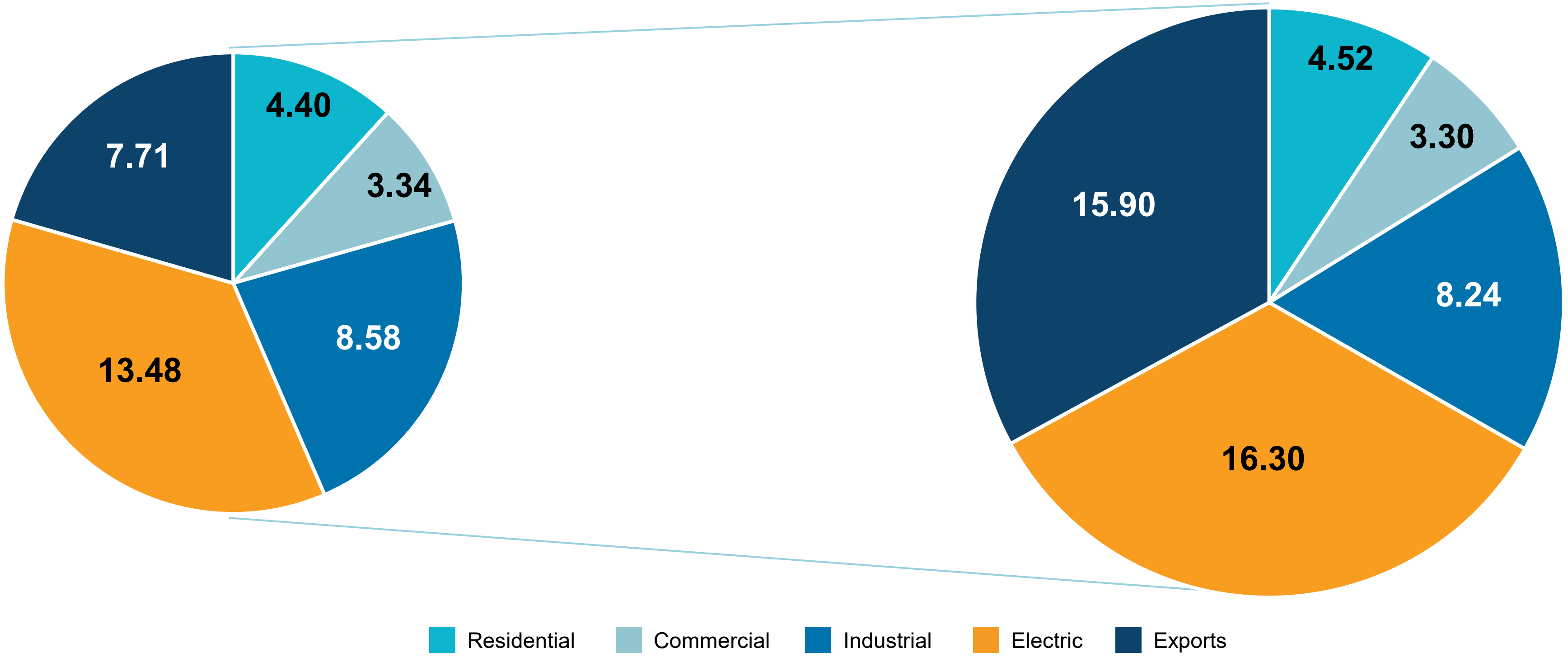
Total US domestic natural gas demand is projected to grow from ~37.5 Tcf in 2024 to ~48 Tcf by 2034 (~30%), with LNG export and electric sector demand serving as the primary contributors of the expected growth.

2024 Total Gas Demand by Sector (Tcf)

Total Demand: 37.5 Tcf

CRA 2034 Total Gas Demand Outlook by Sector (Tcf)

Total Demand: 48.2 Tcf



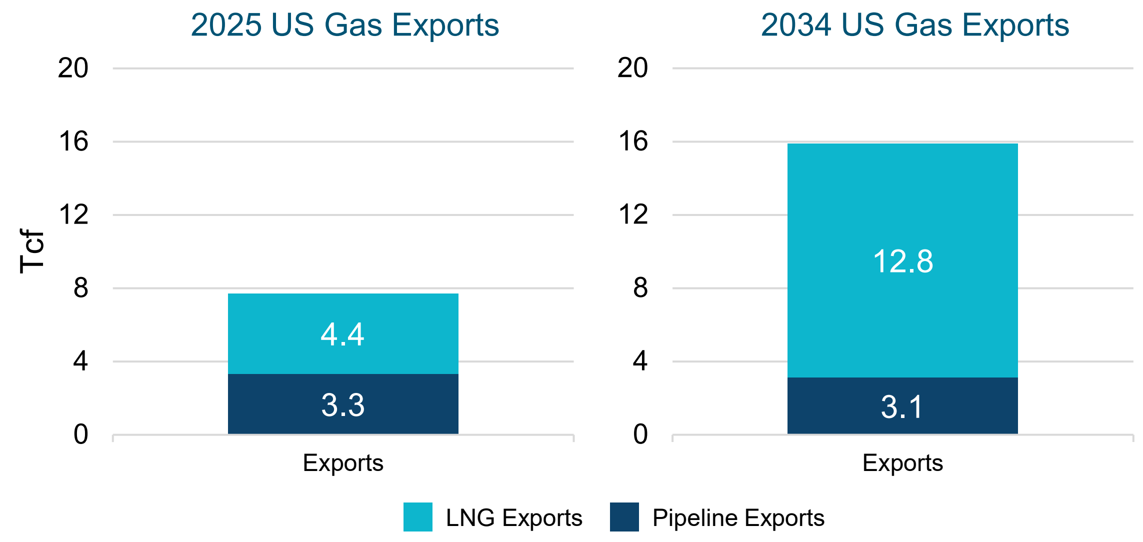
LNG growth globalizes US gas markets

LNG export growth represents a shift in US natural gas markets, with domestic supply now directly tied to global demand patterns.

Current demand is already stretching capacity: In 2024, existing US LNG export facilities operated at approximately 93% utilization; utilization levels are largely driven by growth in importing markets, with Europe (2.10 Tcf) and Asia (1.45 Tcf) accounting for the largest share of US LNG imports that year.

This high demand could drive large expansion: If similar utilization rates are maintained as new capacity comes online to meet growing demand, LNG exports could reach 12 Tcf by 2034.

However, global uncertainties create planning challenges: The pace of the growth is highly uncertain, as India, China, and Japan have all reduced their LNG demand in the past couple years, and European supply-demand dynamics are influenced by geopolitical events and national emissions policies.



Source: U.S. EIA and CRA internal Forward Analysis. 2025 is based on historical gas demand until Sep-2025 and estimation of gas demand for Sep – Dec.

Areas of high LNG demand

- Largest LNG importers by volume (~5.5TCF)
- High demand expected in near term
- Long term outlook expects to reduce dependence on gas

- Japan is the largest single LNG importer globally (3.4 TCF)
- Plans to lower imports, though coal retirements may increase reliance on gas

- Comparable LNG demand to Japan
- LNG imports have been falling for past 13 months, but a partial recovery is expected in 2026
- New pipeline to Russia remains uncertain

Power sector gas demand forecasts are up 45%

CRA's electric-sector demand forecasts are up significantly compared to two years ago.

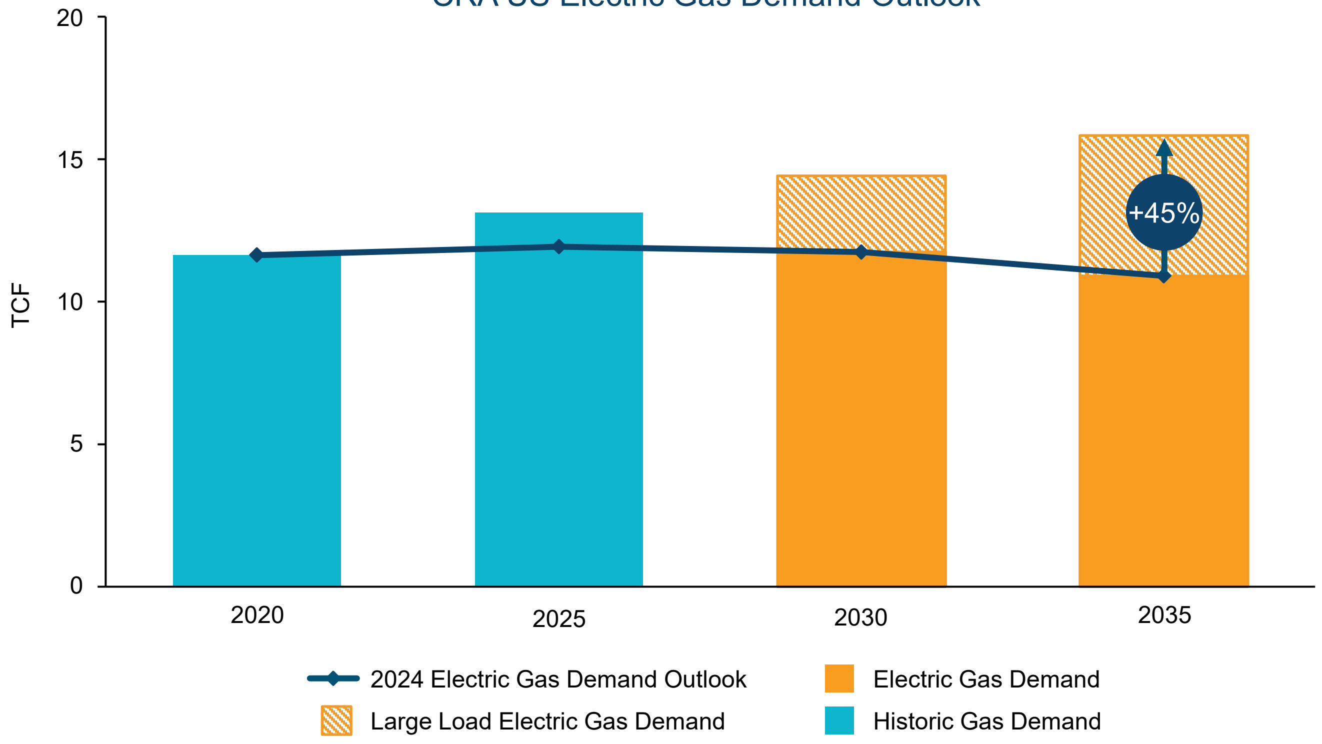
Power sector demand forecasts show significant growth across major regions:

- As per PJM's 2026 load forecast, PJM expects the summer peak to grow by 66 GW (42%) by 2036 and by 97 GW (62%) by 2046.
- Georgia Power's pipeline of large load projects totals 24 GW by 2029.
- ERCOT's peak demand is forecasted to grow by ~40 GW (44%) by 2030.

Data center demand growth has the potential to significantly increase natural gas demand in the power sector by 2035, despite material growth in renewable penetration and energy efficiency gains.

Data centers prioritize firm, dispatchable, and scalable energy solutions to meet reliability, speed-to-market, and cost requirements amid grid and interconnection constraints.

CRA US Electric Gas Demand Outlook



Source: US EIA and CRA internal Forward Analysis. 2025 is based on historical gas demand until Sep-2025 and estimation of gas demand for Sep – Dec.

Natural gas build-out accelerates nationwide

Natural gas remains a primary generating resource that is dispatchable and scalable with existing technology, and the queue of combined-cycle projects has increased across every major power sector region.

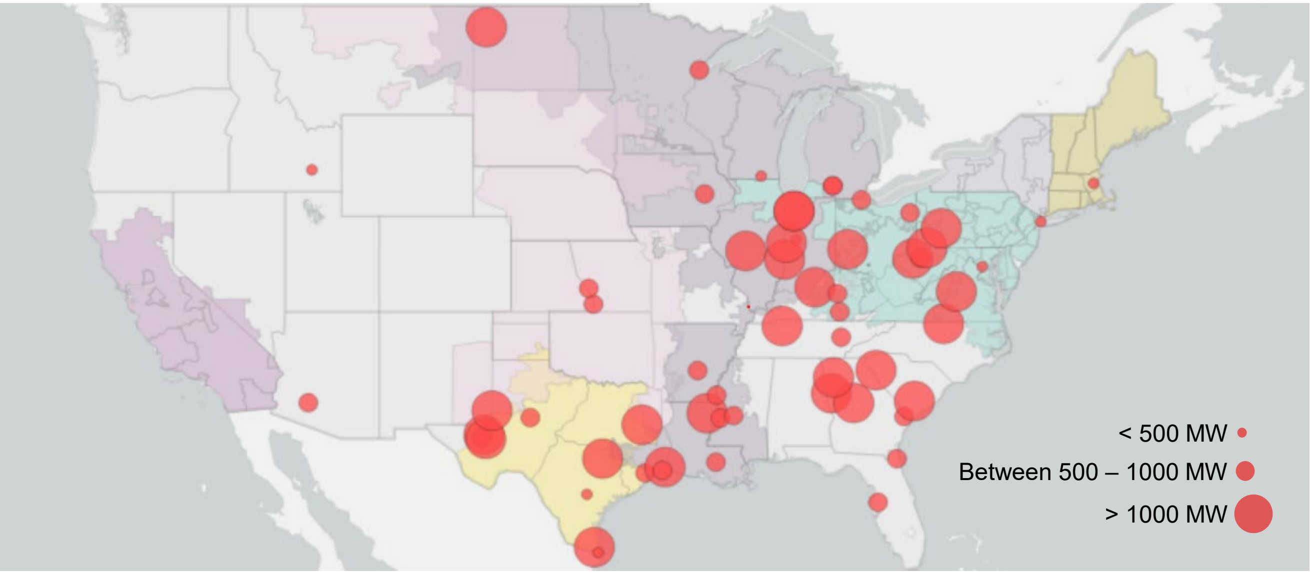
“We’ve observed a clear shift in the US away from a pure “green agenda” toward a growing willingness in many regions to embrace natural gas. How permanent do you think this shift is?”

Respondents are split between medium-term pragmatism (37%) and long-term permanence of gas in the mix (37%), with 26% unsure, pointing to a durable role for natural gas while clean energy “competes on its merits.”

Proposed Combined Cycle Capacity by Region (MW)

	2026	2027	2028	2029	2030	2031	2032	Total
ERCOT		2,163	5,411	2,562				**10,136**
MISO	1,322	625	6,467	2,880	6,116			**17,410**
PJM	940	4,396		579	1,945	3,600		**11,460**
SPP				710	710			**1,420**
SERC	573	673	538	2,981	7,269	5,545		**17,579**
WECC		620	909	346	1,864	360	900	**4,999**

Proposed Combined Cycle Capacity

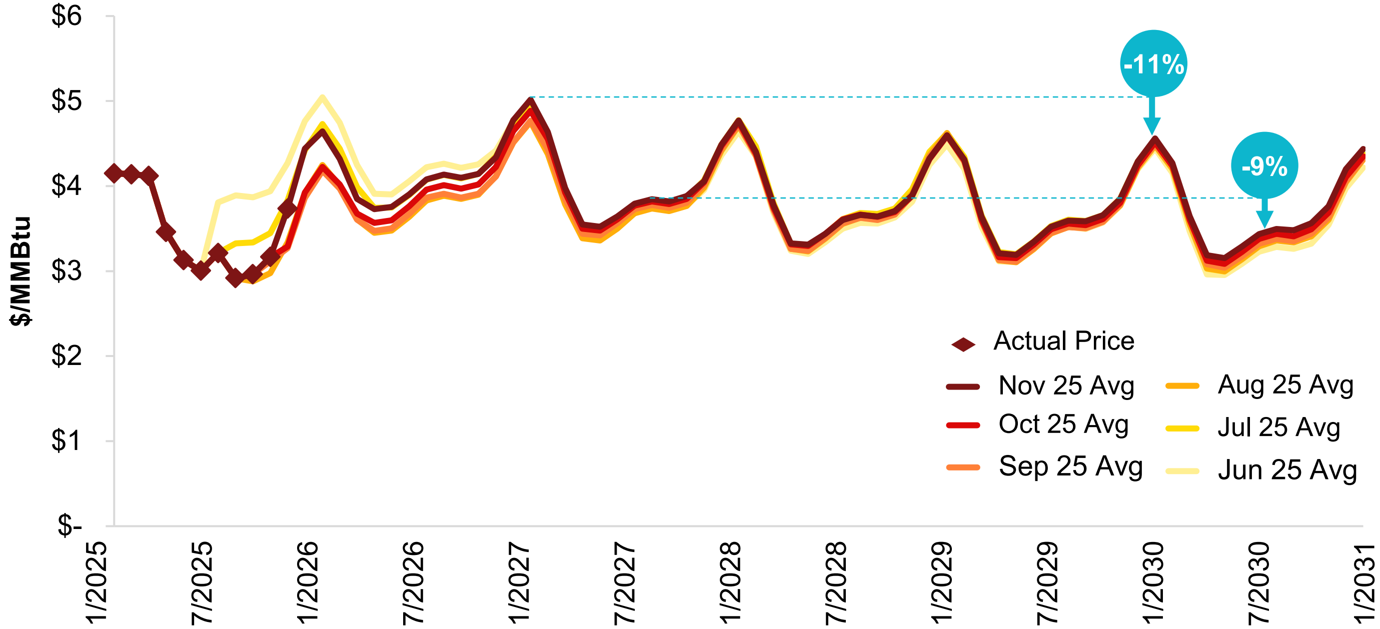


Source: S&P Global.

Forward prices don't yet reflect demand growth outlook

- NYMEX forwards anticipate price declines after 2026.
  - This either indicates that overall demand will decline, or
  - The cost of producing natural gas will go down
- Underpriced forward prices could dampen the supply response, as new drilling requires durable, long-term economics to justify incremental rigs. If demand growth persists, forward prices would be expected to rise, with delayed investment increasing the risk of sharper price corrections as supply tightens. ***Something has to give***.
- Major uncertainties will require careful tracking from market participants:
  - Declining reservoir quality and depletion can reduce well productivity over time (upward price pressure)
  - Projected load growth may not fully materialize, reducing expected gas demand (downward price pressure)
  - More stringent climate or regulatory policies, both domestically and internationally, could constrain long-term natural gas utilization (downward price pressure)
  - Insufficient intrastate pipeline infrastructure in regions such as ISO-NE is impeding transport and increasing risk to demand fulfillment (regional upward price pressure)

NYMEX Henry Hub Forwards Averaged by Month ($/MMBtu)



Henry Hub Annual Average Price ($/MMBtu)						
	Jun 25 Avg	Jul 25 Avg	Aug 25 Avg	Sep 25 Avg	Oct 25 Avg	Nov 25 Avg
2025	3.88	3.63	3.44	3.44	3.46	3.54
2026	4.34	4.17	3.88	3.88	3.97	4.15
2027	3.94	3.99	3.87	3.92	3.97	4.02
2028	3.73	3.85	3.79	3.78	3.81	3.82
2029	3.64	3.74	3.67	3.67	3.70	3.73
2030	3.47	3.57	3.54	3.57	3.61	3.67

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How the natural gas system may rebalance

Forward price re-adjustment – Long-dated Henry Hub forwards rise when producers and their capital providers are unwilling to sell future gas at prices that do not justify drilling, reliability obligations, and infrastructure investment. As sellers pull back from locking in low-priced forward sales and buyers seek firm long-term supply, the forward curve adjusts upward. This is not a policy decision, but an emergent market response to misalignment between prices and the cost of reliable supply.

Increased price volatility – Price volatility rises when demand increases faster than supply can respond. With rig counts constrained and new supply slow to materialize, short-term markets absorb the imbalance through sharper price swings. Volatility becomes the mechanism that prices scarcity and reliability risk when long-term prices have not yet adjusted.

Contracting structures tighten (take-or-pay, firmness premiums) – Contracting terms tighten when sellers are unwilling to guarantee firm supply without stronger commitments. Pipelines, producers, and utilities respond to reliability risk by requiring longer tenors, take-or-pay provisions, or firmness premiums. Buyers accept these terms to secure certainty when spot markets alone cannot deliver reliability.

Higher required returns for infrastructure – Infrastructure investment slows unless capital providers are compensated for higher risk. When long-term prices are low and regulatory or market uncertainty is high, investors require higher returns before funding pipelines, storage, or generation. This raises the cost of infrastructure and limits expansion until returns are sufficient.

Load pays more for firmness – End users ultimately pay more when reliability becomes scarce. Large customers such as LNG exporters, power generators, and data centers face higher delivered gas costs, premium firm transportation, or the need to self-supply. Reliability shifts from being assumed to being explicitly priced and paid for by load.

Strategic implications for energy leaders

Natural gas demand is rising, and reliability expectations are increasing, but supply and infrastructure expand only with strong price and contracting signals. This disconnect complicates both affordability and reliability, leaving energy leaders to manage the tension between near-term affordability and long-term reliability through planning, contracting, and capital decisions.

Implications for utilities

- **Reliability risk increases:** Gas remains critical to resource adequacy as load growth outpaces firm capacity and transmission.
- **Firm supply costs require as much attention as commodity costs:** Greater emphasis on firm supply, longer tenors, and deliverability.
- **Hedging strategies must adapt:** More exposure to volatility and basis risk as supply response lags demand.

Implications for investors and independent power producers

- **Fuel and deliverability risk directly affect project economics:** Assets without firm gas or transport face greater downside during stress events.
- **Capital becomes selective:** Projects with weak contracting or exposure to congestion struggle to attract low-cost capital.
- **Valuation depends on risk profile:** Returns increasingly reflect risk allocation, not just market prices.

So, what now?

Conclusion

The opportunity is to act early

Across North American power systems, reliability, affordability, and deliverability are no longer separable concerns—they are converging under sustained load growth, tighter capacity margins, evolving oversight, and longer implementation timelines.

Together, these dynamics suggest a grid operating under persistent stress, where risks accumulate gradually and outcomes are shaped as much by timing, governance, and execution as by price signals alone.

However, this does not mean the trajectory is fixed—or that utilities and stakeholders are limited to watching pressures accumulate. We are actively working with clients across North America to translate these signals into practical, defensible actions: stress-testing plans against capacity and deliverability constraints, strengthening readiness for evolving oversight, and addressing affordability exposure with fact-based customer impact analysis.

The opportunity is to act early—so reliability and affordability outcomes are shaped by intentional planning and execution, not by reactive decisions made under stress.

Near-term actionable actions

- **Ask for a one-page risk dashboard** – What are the top five regulatory, market, and affordability risks over the next 12–24 months, and where are they showing up in current plans?
- **Request a simple bill-impact view** – How do recent and expected cost pressures translate into customer bills by segment under low, base, and high cases?
- **Pressure-test deliverability assumptions** – Which planned resources, programs, or projects rely on optimistic timelines or non-firm commitments?
- **Clarify what is actually "firm"** – What capacity, flexibility, or cost controls are enforceable under stress versus assumed or aspirational?
- **Align leadership on a single narrative** – What is the consistent explanation of reliability and affordability tradeoffs that regulatory, finance, and operations teams are using?
- **Identify decision triggers** – What signals would cause us to slow, accelerate, or revisit major investments or programs?
- **Inventory upcoming engagement moments** – Which near-term filings, hearings, or stakeholder meetings require a clear, fact-based affordability and reliability story?

About Charles River Associates

CRA overview

Charles River Associates (CRA) is a leading global consulting firm that offers economic, financial, and strategic expertise to major law firms, corporations, accounting firms, and governments around the world.

Key Facts	International Office Locations and Presence

60 + years

- Founded by MIT and Harvard faculty in 1965
- Over 1000 consultants and extended network of senior experts
- 23 offices in 10 countries across various industry practices

North America
Boston, Chicago, College Station, Dallas, Houston, Los Angeles, New York, Oakland, Salt Lake City, Summit, Tallahassee, Toronto, Washington DC, Calgary

Europe
Amsterdam, Brussels, Cambridge, Düsseldorf, London, Munich, Paris, Zurich

Latin America
São Paulo

Australia
Sydney

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CRA's Energy Practice

Data and economic analysis is at the core of what we do which can be applied to a variety of challenges for our clients

	Forward Looking Planning	**Market Fundamentals**	**Corporate Decision Making**
	What do we think the future will look like?	*What environment will we operate in?*	*What decisions do we make today to prepare for tomorrow?*
Sample Applications	• Integrated Resource Planning • Load Forecasting • Supply / demand imbalance • Grid planning	• Policy impact analysis • Resource adequacy analysis • Regulatory requirements • Macro trends (i.e., Data Centers)	• Strategic planning • Capital planning and allocation • Investment due diligence / M&A • Decarbonization strategies • Operating model redesign

Functional Expertise

- **Advanced Data Science/AI**
- **Proprietary and Other Modeling Expertise**
- **Scenario and Impact Analysis**
- **Advanced Analytics**
- **Expert Testimony and Litigation Support**

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CRA's Energy Practice

CRA's Energy Practice provides services to a wide range of industry clients including utilities, ISOs, RTOs, large customers and investors

Our Clients

Regulators/Governments

Institutional Investors

Private Equity

Asset Management

Infrastructure Funds

Industrials

Gas & Electric Utilities

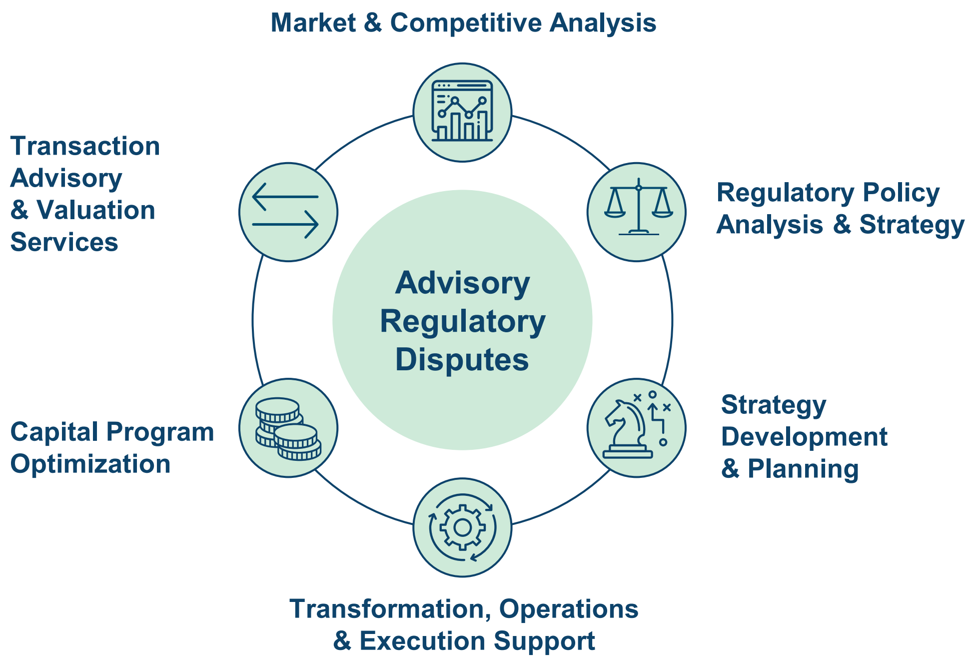
Power Producers

Renewable Developers

Oil & Gas / LNG

Hydrogen & Low-Carbon Fuel Providers

Our Services



Our Value Add for Clients

Sector Experience: Our team has a deep understanding of the energy sector, its transition, and its impact on other parts of the economy.

Specialist Skills: Our team has extensive expertise in energy market modelling, project finance and valuation, risk simulations, scenario analysis, strategy development, capital program execution optimization, restructuring and large-scale transformations.

Varied Perspectives: Our team benefits from the experience of utility executives, regulators, financiers, traders, project developers and strategy practitioners. This allows us to approach issues from different perspectives.

Quality of Output: Our focus on the highest quality output allows our clients to make difficult decisions more confidently and faster.

Collaborative Working: Our expert-led teams work in deep collaboration with clients and their project teams to share and build on existing knowledge for greater understanding.

We help clients make and execute better strategic, operating and organization choices by combining our expert knowledge, analytics, and operational capabilities.

CRA's Energy Practice

CRA combines strategic, regulatory, and economic market analytical insights with hands-on capabilities to transform business to create real value for energy sector clients

Strategy and Management Advisory

Strategy Development
- Strategic planning processes
- Market entry and participation strategy
- Commercial and competitive strategy
- Role of hydrogen in broader strategy

Portfolio and Asset Optimization
- Portfolio design and asset screening
- Trading and hedging approach
- Risk management strategies
- Portfolio mix strategy

Transformation & Implementation
- Business model transformation
- Project management and governance
- Cultural change and stakeholder management

Operational Excellence
- Operational diagnostics
- Business process optimization
- Cost optimization and process design
- Operational excellence review
- Performance management

Market Analysis, Economic, and Regulatory

Market Analysis & Modelling
- Market studies, including pricing and forecasting
- Competitor analysis and benchmarking
- Scenario analysis and development

Regulatory Policy Analysis & Strategy
- Policy design and impact analysis
- Regulatory review and analysis
- Audits and compliance advice
- Regulatory stakeholder engagement

Hydrogen Value Chain Analysis
- Hydrogen economics modelling
- Investment case development
- Hydrogen strategy and project delivery
- Business and commercial options

Transaction Advisory & Valuation
- M&A strategy and target identification
- Asset and company valuation
- Transaction due diligence
- Litigation and damages

Energy, Technology, and Sustainability

Technology Assessment
- Technical and operational process evaluation
- Technology lifecycle GHG emissions
- Policy and subsidy implications

Decarbonization Pathways
- Scenario planning based on technology, climate, and policy
- Capital allocation and investment prioritization

Sustainability
- Decarbonization and net-zero strategy
- Materiality analysis and reporting
- Green finance framework and green bond support

Energy Transition
- Renewables and storage planning
- Future of gas infrastructure
- Biofuels and biogas
- Smart networks

Selected clients

NUCOR, MACQUARIE, AIR PRODUCTS, npower, bp, gasnet, e.on, sse, DTE, suez, Bundesministerium für Wirtschaft und Energie, AXIUM INFRASTRUCTURE, centrica, ESB, CEZ GROUP, NiSource, RWE, wintershall dea, SIEMENS Siemens Financial Services, BASF We create chemistry

Our capabilities and expertise allow us to offer bespoke support to help address specific needs

CRA Charles River Associates

CRA Charles River Associates

www.crai.com

References

Section 1

- *PJM Interconnection, L.L.C.; Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066 (2025).
- The Net Cost of New Entry ("Net CONE") is the minimum capacity price level needed to incentivize the construction of new power plants. Net CONE is an annualized estimate of the necessary $/MW-Day capacity revenue based on the overnight construction costs of a hypothetical resource minus net energy and ancillary service revenues.
- PJM, ELCC Class Ratings for the 2027/2028 Base Residual Auction, link.
- Given the uncertainties involved in restarting a nuclear unit, Figure 4 assumes the Crane Energy Center will come online in 2030, two years after owner Constellation's expected in service date. This figure also excludes RRI projects that have withdrawn from the interconnection queue.
- The three units are: the 950 MW Trumbull CCGT in Ohio expected in 2026; the 930 MW Sycamore Riverside CC in Indiana expected in 2028, and the 4,400-4,500 MW Homer City CCGT gas facility in Pennsylvania expected by 2028/2029.
- PJM, Reliability Resource Initiative Additional Summaries, May 6, 2025, link. Totals exclude wind, coal, and capacity that has withdrawn from the queue.
- *See* American Electric Power Service Corporation, Request for Limited Waiver and Expedited Consideration, November 6, 2026, Docket No. ER26-444.
- Statement of Agreement in Principles Regarding PJM, January 16, 2026, link.
- PJM, Discussion Around Goals, Principles and Elements of a Reliability Backstop Procurement, February 6, 2026, at 15.
- *PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,049 (2026) at P 21.

Section 2

- LBNL study link: link
- Powerlines survey: link
- https://blog.ucs.org/paula-garcia/massachusetts-and-energy-affordability-three-priorities-for-2026/

Section 3

- Compliance Monitoring and Enforcement Program. *CMEP IP 2019-2026.* CMEP Resources.
- NERC Filings to FERC. *Enforcement Dispositions*

Section 4

- Reference CRA EEI Report link

Section 5

- Gas Exports: U.S. EIA and CRA internal Forward Analysis. 2025 is based on historical gas demand until Sep-2025 and estimation of gas demand for Sep – Dec.
- US Electric Demand Outlook: US EIA and CRA internal Forward Analysis. 2025 is based on historical gas demand until Sep-2025 and estimation of gas demand for Sep – Dec.